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August 19, 2011

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
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Email: PUC.FilingCenter@state.or.us

Re: Docket UM 903
CUB's and NWIGU's Joint Comments and Responses to Bench Request

Dear Filing Center:

Attached for filing in the above-referenced document is the original and five (5) copies of CUB's and NWIGU's Joint Comments and Responses to Bench Requests.

This filing was filed and sent to the service list electronically today and has been served on all parties to this proceeding as indicated on the attached Certificate of Service.

Very truly yours,

Tommy A. Brooks

cc: UM 903 Service List

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
UM 903

In the Matter of Northwest Natural 2010 Spring Earnings Review	CUB'S AND NWIGU'S JOINT COMMENTS AND RESPONSES TO BENCH REQUESTS

The Citizens Utility Board of Oregon ("CUB") and the Northwest Industrial Gas Users ("NWIGU") support Staff's Reply Comments in this docket and adopt them by reference and hereby submit these responses to the Bench Requests dated August 3, 2011. CUB and NWIGU are taking the liberty of responding to the subparts of the first UM 903 Bench Request in a different order than the questions were posed in order to make our analysis flow better. We hope that this is not an inconvenience.

Question 1: Commission Discretion/Retroactive Ratemaking.

A. Does the Commission have discretion to determine an equitable result based on the facts presented in a given docket?

Agencies, such as the Public Utility Commission of Oregon, are creatures of statute and are bound by the powers granted to them by the legislature and the general laws affecting administrative bodies.[1] In addition to enabling legislation and general administrative laws, an agency's authority to take a particular course of action may be further limited by the agency's own regulations.[2] Finally, agency orders, though not strictly binding, may provide a source of precedent that restricts future agency action.[3] An agency may choose to deviate from its previous orders as its understanding of the public interest changes,[4] but such a decision will not survive judicial scrutiny without "…a reasoned analysis indicating that prior policies and standards are being deliberately changed, not casually ignored"[5] and without "clearly set[ting] forth the ground for its departure from prior norms."[6] Accordingly, whether an agency has the

[1] *See SAIF Corp. v. Shipley (In re Shipley)*, 326 Or 557, 561 (1998); *City of Klamath Falls v. Environmental Quality Commission*, 318 Or 532, 545 (1994)(quoting *1000 Friends of Oregon v. LCDC (Clatsop Co.)*, 301 Or 622, 627 (1986).
[2] It is axiomatic that an agency must follow its own rules. *Moore v. Oregon State Penitentiary, Corrections Div.*, 16 Or App 536, 537, 519 P2d 389 (1974). Even if an agency is not required to adopt a rule, once it has done so the agency must follow that rule. *Peek v. Thompson*, 160 Or App 260, 265, 980 P2d 178 (1999). Thus, an agency may limit its own discretion by adopting rules. *Wyers v. Dressler*, 42 Or App 799, 807, 601 P2d 1268 (1979), *overruled on other grounds*, 148 Or App 586 (1997).
[3] *See* 73A C.J.S. Public Administrative Law and Procedure § 419.
[4] *See NW Environmental Defense Center v. Bonneville Power Admin.*, 477 F.3d 668, 687 (9th Cir. 2007).
[5] *Greater Boston Television Corp. v.* FCC, 444 F.2d 841, 852 (D.C. Cir. 1970)(affirmed in *NW Environmental Defense Center v. Bonneville Power Admin.*, 477 F.3d 668, 687 (9th Cir. 2007)).
[6] *W. States Petroleum Ass'n v. EPA*, 87 F.3d 280, 284 (9th Cir. 1996)(affirmed in *NW Environmental Defense Center v. Bonneville Power Admin.*, 477 F.3d 668, 688 (9th Cir. 2007).

discretion to take a particular course of action depends first on the agency's statutory authority and the general laws affecting administrative bodies, and then on the agency's self-imposed limitations via administrative rules and, perhaps previous orders.

The Oregon legislature's directive for the Public Utility Commission is broad—the Commission is authorized to approve utility rates that are "fair, just and reasonable"[7] and is "…charged with the duty to protect customers from unjust and unreasonable exactions and practices and to obtain for them adequate service at fair and reasonable rates."[8] The Commission is granted the authority to do "all things necessary and convenient in the exercise of such power and jurisdiction."[9] This language makes clear that the Oregon legislature intended the Commission to have broad discretion to determine, among other things, equitable results for customers based on the facts presented in a given docket, generally.

However, this broad grant of authority and discretion is not without limits. In this case, the Commission's own administrative rules and previous orders have a limiting effect on the Commission's discretion as discussed below.

B. Are the two outcomes proposed by the parties the only legally appropriate ones?

Yes. Despite its broad discretion generally, the Commission must decide between the two outcomes posed by the Parties in this proceeding as a failure to do so would constitute an abuse of discretion.

Over the course of more than a decade and through several dockets, the Commission has approved a detailed and specific framework of policies, rules, standards and guidelines that govern the earnings review process. In AR 357, the Commission established the procedural steps for PGA filings and associated earnings reviews and then enacted OAR 860-022-0070 to govern the role and application of earnings reviews.[10] As stated in OAR 860-022-0070(1):

> The purpose of sections (1) through (7) of this rule is to ensure that earnings of a natural gas utility local distribution company ("gas utility" or "LDC") with a purchased gas adjustment ("PGA") mechanism are not excessive prior to passing through prudently incurred base gas cost changes in rates **through a mechanism which is fair to all parties and efficient to administer**. For purposes of this rule, **earnings are excessive only if a gas utility does not share with its customers past revenues related to earnings that exceed an earnings threshold determined by the Commission**.[11]

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[7] ORS 757.210(1)(a).
[8] ORS 756.040(1).
[9] ORS 756.040(2).
[10] Order No. 99-284 (April 21, 1999).
[11] OAR 860-022-0070(1)(emphasis added).

OAR 860-022-0070(5)(b) provides a specific directive for the treatment of normalizations and adjustments in earnings reviews:

> The test year results will be adjusted with a predetermined list of rate-making adjustments equivalent to those applied in the gas utility's most recent general rate proceeding.[12]

In UM 903, the Commission initiated an investigation to examine policies and procedures related to the recovery of purchased gas costs by Oregon LDCs; the primary issues for review included "the appropriate structure of the risk-reward sharing incentive mechanism for gas cost differences and the role and structure of earnings review."[13] Order No. 99-272 provides the specific standards for the earnings review and sharing mechanisms, including a list of rate-making adjustments ("Type I" adjustments) that are to be made when calculating earnings for Spring Earnings Reviews, in accordance with OAR 860-022-0070(b)(5):

- Making significant ratemaking adjustments not reflected on books (advertising, memberships, uncollectable expenses, officers' bonuses and other incentive plans, and major rate base adjustments);
- Removing non-operating items that were improperly recorded above the line;
- **Removing entries related to prior period activity, and including subsequent period transactions clearly related to the test period**;
- Making an interest coordination adjustment to restate income taxes based on the interest deduction implied by the weighted cost of debt and the rate base in the earnings report;
- Removing the effect of any temporary rate adjustment in the period, including any related to prior earnings review.[14]

The regulatory framework for adjustments in the Spring Earnings Review is clear—OAR 860-022-0070 establishes the procedures for earnings review, including the procedure for determining adjustments, and Order No. 99-272 provides the list of allowable Type I adjustments. A modification of the earnings test mechanism to address the particular facts of one docket in hopes of reaching an equitable result runs counter to the very purpose of the earnings test—to achieve an equitable result for all parties in a manner that is efficient to administer for all parties. Additionally, such a modification skews the balance achieved by the original earnings test design and runs counter to previous Commission orders. Therefore, an ad hoc adjustment to the regulatory framework based on the particular facts of a given docket would be an abuse of discretion on the part of the Commission.

[12] OAR 860-022-0070(5)(b).
[13] Order No. 99-272, pg 1 (April 19, 1999).
[14] Order No. 99-272, Appendix B at 1 (April 19, 1999)(emphasis added). The Commission also ordered that LDCs could make a one-time selection as to whether to make weather normalizing adjustments. *Id.*

Simply put, NW Natural is arguing that the property tax adjustment is properly removed because it is "related to prior period activity."[15] Staff, CUB and NWIGU argue the opposite—that the property tax adjustment is in fact related to in-period activity, and therefore appropriately considered when calculating earnings for the Spring Earnings Review.[16] There is no hybrid between in-period and out-of-period activities; the property tax adjustment can only be placed in one category. Therefore, despite the Commission's general authority to render an equitable remedy based on the facts presented in a given docket, the Commission must decide whether the property tax adjustment is appropriately characterized as an in-period activity, and if so, it must treat the property tax adjustment in accordance with the regulatory framework to which the Commission has bound itself through administrative rule-making and previous Commission orders. To do otherwise would be an abuse of discretion.

C. Would a decision based on the Commission's hypothetical approach of reanalyzing prior earnings tests from 2003 to 2009 constitute retroactive ratemaking?

In Order No. 08-487, the Commission comprehensively discussed the rule against retroactive ratemaking, deciding on a narrow application in Oregon.[17] The Commission noted that the intent behind the rule is "to ensure that customers are paying rates that reflect the cost of service at the time service is rendered."[18] The Commission also stated that the Rule "does not necessarily prohibit the calculation and imposition of refunds."[19] As stated by the Commission, the Rule explicitly prohibits: (1) consideration of past losses or past profits in future rates, and (2) retroactively adjusting past rates to "true-up" the estimated expenses and revenues used in the rate case test year to a utility's actual expenses and revenues.[20] The Commission acknowledged two statutory exceptions to the Rule found in ORS 757.259 and ORS 757.268, neither of which is applicable to the situation at hand.[21]

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[15] NW Natural's Opening Comments, pg 6-7.
[16] NW Natural states that Staff does not take the position that this is not an out of period adjustment; this is not a correct characterization of Staff's position. UM 903 Staff's Opening Comments, pg 3-4 (July 27, 2011).
[17] *See* Order No. 08-487, pg. 36-41 (September 30, 2008).
[18] Order No. 08-487 at 36.
[19] *Id.* at 37.
[20] *Id.* at 40-41.
[21] ORS 757.259 addresses deferrals and amortizations in the context of ratemaking and allows utilities to recover identifiable expenses or revenues in future rates under certain circumstances (discussed in Order No. 08-487, pg. 38-39); ORS 757.268 addresses adjustments to rates by reason of income taxes paid by a public utility to ensure that customers are only charged in rates for income taxes that a utility *actually* pays to taxing authorities (discussed in Order No. 08-487, pg. 39). Because the adjustment proposed by the Commission would not involve an adjustment of rates, but rather of Spring Earnings Reviews of past years, neither of this statutory exceptions are directly on point.

Generally, as a threshold matter, a party must challenge a Commission order in a court of law before the Commission can legally engage in retroactive ratemaking as part of its remedial authority outside of the statutory exceptions.[22]

CUB and NWIGU are not supportive of the Commission constructing an alternative earnings test calculation for this docket by reanalyzing earnings tests from 2003 to 2009 for 2010 utility income from a property tax refund and related interest. To the contrary it remains CUB's and NWIGU's position that with a well-established and thorough earnings review mechanism already in place, it may be inappropriate, and even unlawful, for the Commission to create an ad hoc process to deal with issues in the hypothetical manner suggested by the Commission's bench request in this individual docket. There simply is no statutory support for the Commission to take such an action. Thus, were the Commission to decide to create a separate process for this docket such action could result in litigation from some of the interested parties.

Question 2: Is the tax judgment an "in-period" adjustment properly attributed to the 2010 earnings review period under existing Commission precedent, or an out-of-period adjustment that should nevertheless be included in the 2010 earnings review process as an exception to existing Commission precedent?

NWIGU and CUB believe that the property tax judgment is an "in-period" activity properly attributed to the 2010 earnings review period under existing Commission precedent. At issue here is whether NW Natural can remove from its 2010 Results of Operations ("ROOs") a refund actually received in 2010 for property taxes it paid in prior periods and still be consistent with the utility's practice of adjusting property tax expense in ROOs for those prior periods so that NW Natural's earnings reflected NW Natural's actual property tax expense.

The purpose of the Commission requiring a utility to remove expense or revenue for a prior period activity is to make certain that the cash-flow being measured appropriately matches the activity in the period. As Staff has noted in its response to the Bench Requests, this is a common approach for developing a test period in order to avoid distorting the actual financial picture of a utility. Thus, when developing a forward-looking test year, it makes sense to remove one-time proceeds that are not likely to re-occur as part of a utility's expected income.

Unlike a test year developed for future rate-making, the "test year" required by OAR 860-022-0070(5)(a) is not a forward-looking test year. Rather, it is based on a prior calendar year used to calculate a utility's actual earnings in that prior year. NW Natural has consistently made adjustments to the amounts it actually paid in property taxes in order to adhere to this principle

[22] ORS 756.565 provides that the Commission orders are only *prima facie* lawful pending judicial review: "All rates, tariffs, classifications, regulations, practices and service fixed, approved or prescribed by the Public Utility Commission and any order made or entered upon any matter within the jurisdiction of the commission shall be in force and shall be prima facie lawful and reasonable, until found otherwise in a proceeding brought for that purpose under ORS 756.610." ORS 757.565.

and to develop a test year for its earnings review that accurately reflects its earnings that year. NW Natural's desire to remove the refund now is contrary to those past practices. Moreover, it is contrary to the characterization of this income in its own reporting to its shareholders, to the SEC and to the IRS. If NW Natural were committed to its position that the property tax refund relates to an activity for a prior year, then it would make corresponding adjustments to those prior year activities and file amended returns to re-state its earnings and income in those years. Instead, NW Natural is treating the property tax refund as part of its cash flow for 2010 and, therefore, treating the property tax refund as a 2010 activity. The refund is thus an in-period activity for purposes of its earnings review.

Question 3: Relevant precedent, either in Oregon or in other jurisdictions, that might inform the Commission's analysis of how a court judgment should be treated for regulatory purposes.

CUB and NWIGU discovered the same precedent to which Staff cites in its response to the Bench Requests. CUB and NWIGU support Staff's characterization of those decisions and their implication to the present matter.

Property tax refunds for utilities are common in many jurisdictions across the United States. A commission's treatment of property tax refunds, or refunds in general, depends largely on the specific statutes, rules, and previous commission orders that bind the commission in any given jurisdiction.[23] As discussed above, the Oregon Public Utilities Commission is also a creature of statute, subject to its enabling legislation, general administrative laws, its own rules and, under certain circumstances, its previous orders. Additionally, the precedent in other jurisdictions addresses the treatment of property tax refunds in the context of ratemaking, rather than an earnings review process as is the case in this docket. For those two reasons, CUB and NWIGU feel that the precedent in other jurisdictions is of limited value to this Commission in the context of this proceeding.

We note for the record, however, that several jurisdictions have stated or upheld the sentiment that when a ratepayer bears the cost of paying for a particular expense, it is the ratepayer who should get the benefit of the refund of all or a portion of that expense. When addressing the treatment of a potential future tax refund, the Missouri Public Service Commission stated:

> If [Company] does receive a refund, then the Commission would certainly expect that the company would return that refund to its customers who are ultimately paying the tax bill. It is hard to imagine any circumstance in which such a refund

[23] *See* Providence Water Supply Board's Application to Change Rate, 2007 WL 4476140 (R.I.P.U.C.); *Orange and Rockland Utilities, Inc.*, Order Setting Permanent Rates, Reconciling Overpayments During Temporary Rate Period and Establishing Disposition of Property Tax Refunds, Cases 06-E-1433, 06-E-1547 at 35-38 (N.Y.P.S.C. October 18, 2007); *Ponderosa Telephone Company v. PUC*, 197 Cal.App.4th 48, 61 (2011); *In the Matter of Union Electric Company*, 2011 WL 2962024 (Mo. P.S.C.); *Beaver County v. Qwest Corporation*, 2005 WL 1566660 (Utah P.S.C.). Attached to these comments is an index containing the decisions from other jurisdictions cited to in this section of CUB's and NWIGU's Joint Responses.

would not be ordered. However, such an order must wait for a future rate case in which that decision will be presented to the Commission.[24]

In another proceeding, the Illinois Commerce Commission created a mechanism for a utility to pass on recovery of insurance proceeds related to environmental cleanup to ratepayers, the parties who had borne the cost related to those recoveries. The Commission stated:

> "...any benefit that the Company receives from insurance proceeds related to environmental recoveries, no matter when received, should be included in any revisions of [Environmental Remediation Costs Rider] adjustments between annual calculations."[25]

CUB and NWIGU acknowledge that the mechanism in that case is different than the present matter because it was being used to establish forward-looking rates. However, the policy basis for the decision remains relevant and is informative. In the *Commonwealth Edison* matter, the utility incurred specific costs (environmental remediation) over multiple periods of time that may or may not be offset later through insurance proceeds. Once those proceeds were realized, they were not to be treated as a windfall to the utility. Rather, they were to be credited to those who bore the costs of the environmental remediation in the first place – the ratepayers. Similarly, NW Natural has incurred specific costs (property taxes) over multiple periods of time that may or may not have been offset by refunds resulting from litigation. Now that those proceeds have been realized, they should be credited in the 2010 earnings review to those who bore that burden initially in prior earnings reviews – the ratepayers.

Finally, CUB and NWIGU feel it is important to note that in the cases in which a commission allowed a utility to keep some portion of a property tax refund as an incentive to keep rates lower by challenging property tax assessments, the commission deemed a 10% award to a utility to be "ample award for the Company's efforts."[26] This is a far cry from the 67% that NW Natural stands to retain in the case at hand.

Dated in Portland, Oregon this 19th day of August, 2011

Tommy A. Brooks FOR

Catriona McCracken
Citizens Utility Board of Oregon

and

Paula E. Pyron
Northwest Industrial Gas Users

[24] *In the Matter of Union Electric Company*, 2011 WL 2962024 (Mo. P.S.C.).
[25] *In re Commonwealth Edison Co.*, 250 P.U.R.4th 161, 164 (Illinois P.S.C. 2006).
[26] *Orange and Rockland Utilities, Inc.*, Order Setting Permanent Rates, Reconciling Overpayments During Temporary Rate Period and Establishing Disposition of Property Tax Refunds, Cases 06-E-1433, 06-E-1547 at 37 (N.Y.P.S.C. October 18, 2007).

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Rhode Island Public Utilities Commission
December 13, 2007

Slip Copy

REPORT AND ORDER

IN RE: **PROVIDENCE WATER SUPPLY BOARD'S APPLICATION** TO **CHANGE RATE** SCHEDULES
3832

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I. Introduction

On March 30, 2007, Providence Water Supply Board ("Providence Water") made a general rate filing with the Public Utilities Commission ("Commission"). The rate filing, if approved, would result in an overall revenue increase of $9,688,321 or 19.07 percent, increasing rates by 19.6 percent, for a total cost of service of $60,495,441. The effect on a typical residential customer with annual consumption of 100 HCF would be an increase of $41.60 or 17 percent, from $244.56 to $286.16 per year or approximately $10.40 per quarter.[FN1] Providence Water requested an effective date of April 30, 2007.[FN2] On April 19, 2007, the Commission suspended the filing. On May 14, 2007, Kent County Water Authority ("KCWA") filed a Motion to Intervene based on its status as a wholesale purchaser of water from Providence Water.[FN3] No objection was filed and the Motion was granted in accordance with Rule 1.13(e) of the Commission's Rules of Practice and Procedure.[FN4]

FN1. Providence Water Exhibit 7 (Pre-Filed Testimony of Harold J. Smith), p. 9.

FN2. Although Providence Water requested an effective date of April 30, 2007, it presented its filing based on an effective date of January 1, 2008.

FN3. In his Direct Testimony on behalf of KCWA, Mr. Woodcock lists co-intervenors as: East Smithfield Water District, the Town of Lincoln-Lincoln Water Commission, Greenville Water District, the City of East Providence, and the City of Warwick.

FN4. On May 21, 2007, KCWA filed a Motion to Pass Through Wholesale Rates. This Motion was assigned Commission Docket No. 3843.

This is Providence Water's third request for rate adjustments in the past eight years. A brief history follows:

Docket No.	Filing Date	Effective Date	Increase Requested	Increase Allowed	Percentage Increase
3684	6/30/05	1/1/06	$4,957,115	$4,065,347	9.2%
3446	7/1/02	1/1/03	$5,448,798	$4,658,599	11.1%
3163	6/30/00	1/1/01	$5,416,622	$2,813,974	7.34%

In its filing, Providence Water indicated that the rate increase was necessary primarily due to the following: (1) increases for Infrastructure Replacement ("IFR") ($2,000,000); (2) increases in insurance costs ($1,000,000); (3) increases in chemical and sludge costs ($1,073,654); (4) increased costs associated with post-retirement health care benefits ($403,243); (5) request to recover past retiree health care benefits paid by the City of Providence, but not charged to Providence Water ($300,000); (6) increases in property taxes ($540,738); (7) an increase in operations revenue allowance ($862,860); (8) funding for strategic planning ($150,000); (9) increase in City Service Expense ($515,958); (10) wages and benefits ($1,831,163); (11) Purchase Power ($543,698); and (12) other known and measurable increases.[FN5]

FN5. Providence Water Exhibit 2 (Pre-Filed Testimony of Pamela Marchand), pp. 3-4.

II. Providence Water's Pre-Filed Testimony

Providence Water submitted the Direct Pre-Filed Testimony of Pamela Marchand, P.E., General Manager, Jeanne Bondarevskis, Director of Finance, Paul Gadoury, Director of Engineering, David Bebyn, consultant to Providence Water, Walter E Edge, Jr., consultant to Providence Water, and Harold Smith, consultant to Providence Water. Ms. Marchand provided an overview of the filing and the general reasons for the requested increase.[FN6] Ms. Marchand indicated that while Providence Water used a rate year ending calendar year 2008, Providence Water was requesting rates be implemented for usage on and after November 1, 2007.[FN7]

FN6. *Id*. at 1-5.

FN7. *Id*. at 5.

In addressing proposed changes to the methodology of funding Providence Water's IFR program, Ms. Marchand recognized that in the past, the utility has depended on the pay-as-you-go approach as being the most economical to customers because it carries with it no interest. However, she noted that in the past year, Providence Water has identified additional major capital expenses which would be more appropriately addressed through bonding in order to maintain customer rates at a reasonable level. She stated that Providence Water was requesting funds for debt service in order to replace seven percent of the utility's lead services per year and to renovate the water treatment filtration system and sedimentation system.[FN8] Ms. Marchand explained that Providence Water must replace the lead services because the utility exceeded the EPA Action Level for lead in water samples taken from customer taps in August 2006.[FN9]

FN8. *Id*. at 6.

FN9. *Id*. at 7.

Addressing the request for a 100 percent increase in Providence Water's operating reserve, Ms. Marchand listed the costs which increased during fiscal year 2007, the same period of time during which Providence Water experienced decreased consumption.[FN10] Finally, Ms. Marchand addressed the need for a strategic plan, explaining that it would include "an asset management program to focus the funding and manpower where it is the most effective in accomplishing the mission of Providence Water and to direct the most efficient use of ratepayer funds."[FN11] She testified that this would not be a one-time expense, but rather, in subsequent rate years the funds requested for the study would be paid to a consultant to implement the plan developed.[FN12]

FN10. *Id*. at 7-8.

FN11. *Id*. at 10.

FN12. *Id*. at 11.

Ms. Bondarevskis provided more detail regarding the lead abatement program and water treatment projects, noting that the financial effect of implementing these changes would result in a projected deficit of $83 million over the next twenty years without additional debt service.[FN13] Addressing changes to the Automated Meter Reading ("AMR") fund, Ms. Bondarevskis noted that meter installation has been funded through the AMR fund while replacements have been funded by IFR funds. Now that the AMR fund is nearing completion, Ms. Bondarevskis suggested that transferring funds from IFR to the AMR fund would allow all AMR related activities to be funded from one account.[FN14]

FN13. Providence Water Exhibit 3 (Pre-Filed Testimony of Jeanne Bondarevskis), pp. 2-5.

FN14. *Id*. at 5-6.

Explaining Providence Water's request to pay to the City of Providence ("City") approximately $1.6 million over five and one-half years, Ms. Bondarevskis stated that Providence Water had not been reimbursing the City for the cost of Providence Water's retirees' health care. She stated that "this was discovered in fiscal year 2006."[FN15] She opined that it was not discovered earlier because "[f]or some time now Providence Water has not reimbursed the City for Health care costs for employees in a direct manner," but rather, when payroll is completed, the City wires the amount needed for payroll and fringe benefits.[FN16] Therefore, there was no invoice for Providence Water to process and according to Ms. Bondarevskis, Providence Water was unaware that the utility was not being charged for its retirees' health care.[FN17] In order to calculate the amount to be paid back, the City Controller's office started with actual costs for fiscal years 2005 and 2004, discounted the costs back for each fiscal year 2003 through 1997, based on the annual working rate increase.FN18 In Ms. Bondarevskis' opinion, this was “a reasonable method of estimating the outstanding liability.”FN19

FN15. *Id*. at 6-7.

FN16. *Id*, at 7.

FN17. *Id*.

FN18. *Id*. at 8.

FN19. *Id*.

Finally, addressing cash flow issues, Ms. Bondarevskis expressed support for Providence Water's proposed changes to rate design which would allow Providence Water to collect more revenue from fixed service charges rather than from metered consumption charges. In addition, she expressed support for the increased net operating revenue allowance. She indicated that this would provide more of a cushion against reduced revenues.FN20

FN20. *Id*. at 8-9.

Mr. Gadoury provided testimony regarding modifications to Providence Water's Infrastructure Replacement (“IFR”) Plan and the impact of weather on consumption. Providence Water's IFR plan, approved by the Rhode Island Department of Health on February 7, 2007 was estimated to cost approximately $248,425,000 over 20 years. However, since then, Providence Water has expanded and accelerated the replacement of lead services in order to comply with EPA regulations and State and Federal regulatory orders, has expanded the scope of work for the Water Treatment Plant Filter Rehabilitation project, and has modified its approach to rehabilitate the sedimentation basins.FN21 He explained that the lead service replacements will cost more than double what was originally planned and has to be completed in a shorter time frame.FN22 Modifications to the filter project are estimated to add $15 million to the previously estimated $25 million cost, but Mr. Gadoury indicated that benefits would include the ability to increase the depth of the filters in order to meet current minimum standards, the ability to utilize granulated active carbon (“GAC”) filter media in the future, eliminate hidden filtration system components for easier monitoring, simplify the repair and replacement process of filters, and eliminate the problem of groundwater contamination.FN23 Because of the proposed changes to the filtration system, Mr. Gadoury explained that the original plan to rehabilitate the plant's sedimentation basins needed to be revised.FN24 Mr. Gadoury confirmed that plans are being submitted to RIDOH for review and the costs would be paid for through bonds and an increase in IFR rate revenue.FN25

FN21. Providence Water Exhibit 4 (Pre-Filed Testimony of Paul Gadoury), pp. 2-5.

FN22. *Id*. at 5.

FN23. *Id*. at 8-10.

FN24. *Id*. at 10-12.

FN25. *Id*. at 12-13.

Discussing annual demand for water, Mr. Gadoury indicated that summer weather patterns have the most effect on the demand. Mr. Gadoury noted that over the most recent 10 year period, average demand had fluctuated from year to year. Because of the “up and down variations in the total demand from year to year,” he noted that Providence Water was proposing changes to the rate structure to reduce the effect of demand fluctuations on revenue.FN26

FN26. *Id*. at 13-15.

Mr. Bebyn provided testimony to explain the normalizing adjustments he made to the Test Year (FYE June 2006).FN27 Mr. Bebyn also provided testimony regarding the proposed $1.24 million City Service expenditures for the Rate Year (CY 2008), an increase of almost 50 percent over the previously allowed City Service expense. Mr. Bebyn discussed his review of City Service expenses, including meeting with some department heads, reviewing actual fiscal year expenses for each department and reviewing the fiscal year 2007 budgeted expenses. He indicated that the previous allocation model used for City Service expense was not detailed enough to properly allocate the costs. He stated that using the prior model approved in Docket No. 3163, City Service expense would increase to almost $2.1 million. FN28

FN27. Providence Water Exhibit 5 (Pre-Filed Testimony of David Bebyn), pp. 2-3.

FN28.*Id*. at 5-6.

Mr. Bebyn summarized his reasons for allocating costs to Providence Water from various City departments. He stated that the mayor's office "deals with Providence Water issues on a regular basis."FN29 He indicated that the City Council and City Council Administration are appropriately allocated to Providence Water because the Council passes laws and ordinances affecting Providence Water and approves its budget.FN30 Mr. Bebyn testified that the City Finance Department does not provide a duplication of services to the Providence Water Finance Department because the City Department "provides oversight for all Providence Water's financial transaction[s] and monitors their budget."FN31 He also allocated a portion of two non-departmental service costs, including Stop Loss Insurance and a new GASB 43/45 consultant expense.FN32 Once Mr. Bebyn had reviewed the various departments, he created allocators which he applied to the various departments.FN33

FN29.*Id*. at 7.

FN30.*Id*.

FN31.*Id*. at 9.

FN32.*Id*. at 13-14.

FN33.*Id*. at DGB-6.

The General Overhead Allocator of 8.14 percent, applied to the Mayor's office, City Council, City Council Administration, Law Department, Finance Department, Controller's Office, Data Processing, Internal Auditors, and Archives, was developed by taking the total Providence Water audited operating expenses less depreciation and dividing it by Providence Water operating expenses less depreciation plus the City operating expenses less debt service. The factor was then applied to the Total Departmental Expense less any amount clearly not at all related to Providence Water plus 72 percent fringe benefits not expensed in department accounts.FN34

FN34.*Id*. at DGB-4, DGB-6.

A separate allocator of 12.48 percent was created for the City Clerk's office by taking the number of Providence Water activities (bid processing) divided by the total for the clerk's department.FN35 The allocator was applied to the total City Clerk's departmental expense plus a 72 percent fringe benefit allowance.FN36 A 10.99 percent employee related allocator was created by taking the number of Providence Water employees compared to the total of City and Providence Water employees and was applied to total expenses of the Retirement and Personnel Departments plus a 72 percent fringe benefit allowance.FN37 This allocator was also applied to the Stop Loss Insurance and Annual GASB 43/45 consulting fee. A separate Treasury Allocator of 9.0 percent was created by taking the Providence Water checks processed and dividing that number by the total of City checks plus Providence Water checks. This allocator was then applied to the total Treasury department expense minus two accounts not related to Providence Water plus fringe benefits in the amount of 72 percent. FN38 Finally, a 12.16 percent purchasing allocator was developed by taking the number of Providence Water contracts divided by the total of City and Providence Water contracts. The factor was applied to the total Personnel Department costs minus three accounts not related to Providence Water plus 72 percent in fringe benefits.FN39 Mr. Bebyn arrived at a total City Service expense allocation to Providence Water of $1,245,952; this included $62,599 for Stop Loss Insurance and GASB 43/45 consulting fees and an inflation allowance of $60,234.

FN35.*Id*. at DGB-6. Mr. Bebyn originally testified that he counted the number of resolutions and bid notifications, but clarified on cross-examination at the hearing that he only compared bids. See*Id*. at 8, Tr. 9/13/07, p. 77.

FN36. Providence Water Exhibit 5, DGB-4, p. 1.

FN37.*Id*. at DGB-4, p. 2, DGB-6.

FN38.*Id*.

FN39.*Id*.

Mr. Edge's testimony addressed specific adjustments related to the requested increase. He noted that Providence Water was requesting a 19.07 percent increase in revenues, but that the increase would not be uniform across-the-board based on the rate design model developed by Mr. Smith in this proceeding.FN40 Discussing the Rate Year of CYE December 31, 2008, Mr. Edge proposed increases to twelve groups of accounts: (1) Salaries and Wages ($947,203); (2) Property Taxes ($540,738); (3) Insurance expense ($1,000,000); (4) Pension and Other Benefits ($884,140); (5) Regulatory and Rate Case expense ($89,036); (6) Chemicals and Sludge ($1,073,654); (7) Purchased Power ($543,698); (8) IFR/Restricted Funding ($2,000,000); (9) GASB 43/45 Health Insurance ($403,243); (10) Health Insurance Liability (City) ($300,000); (11) City Services ($515,958) to match the results of Mr. Bebyn's study; and (12) Study for Strategic Planning ($150,000). Additionally, Mr. Edge “increased all remaining accounts for inflation (2.5% per year), and made an adjustment for the net operating income allowance at 3%.”FN41

FN40. Providence Water Exhibit 6 (Pre-Filed Testimony of Walter E. Edge), p. 4.

FN41.*Id*. at 6, 17.The 2.5 percent was allowed in the prior rate case. *Id*. at 18.The $1,725,719 operating reserve was calculated by subtracting miscellaneous revenue from total expense and multiplying the result by 3.0 percent, the request in this docket. *Id*. at 19.

Adjusting salaries and wages, Mr. Edge increased test year levels upward by 3.0 percent per year through CY 2008, in accordance with historical increases, for a total of 7.5 percent despite the fact that there is no current union contract for FY 2008 and 2009. He rationalized the adjustment by noting that when labor contracts are finalized, the salaries and wages are usually implemented retroactively back to the end of the last contract. FN42

FN42.*Id*. at 7-8.

Because he did not have actual property tax bills, Mr. Edge increased fiscal year 2007 tax bills by 7.5 percent to reflect the maximum allowed five percent increase for each municipality for FY 2008 and CY 2008. However, he indicated he would advise the parties of the actual costs when they become known.FN43 Similarly, to project the rate year insurance expense, Mr. Edge used the actual insurance expense for FY 2007 and increased the expense by 10 percent for FY 2008 and 5 percent for CY 2008, an amount Providence Water's insurance carrier indicated was reasonable. However, Mr. Edge also noted that the insurance fund had a shortfall which needs to be addressed. Therefore, he increased the account by an additional $600,396 to avoid future shortfalls. FN44

FN43.*Id*. at 8-9.

FN44.*Id*. at 9-11.

With regard to pension and other benefits, Mr. Edge left Union Combined Benefits, Laborers International Pension and Life Insurance Premium at test year levels. He increased FICA and wage assignment in accordance with his projected wage increase. He increased dental and health care over test year levels by 10.68 percent and 27.35 percent, respectively. Additionally, he increased the relatively new GASB 43/45 reserve to cover Providence Water's contribution to the reserve for future retiree health care in a percentage equal to that which will be deposited by the City. He also included $300,000 to reimburse the City for past retiree health care costs. Finally, Mr. Edge increased Providence Water's contribution to the City Retirement fund per the consultant's report.FN45

FN45.*Id*. at 12, 15-16, WEE-6.

Mr. Edge increased Regulatory Commission expense to $186,587, and he amortized the current rate filing costs over two years for an annual amount of $105,400. The total Regulatory/Rate Case expenses for the rate year totals $291,987, an increase of $89,036. He increased restricted Chemicals and Sludge by multiplying the projected FY 2008 usage by the CY 2008 projected price. He also increased the rate year amount by $200,000 to cover a projected deficit in the Chemical account in FY 2010. With regard to Purchased Power expense, Mr. Edge noted that there was a 46 percent increase from FY 2004 through FY 2006, and although Mr. Edge was uncertain such an increase would occur, he utilized that increase to project the increase from FY 2006 through FY 2008 and then increased that result by an additional 5 percent to derive the pro forma rate year expense. FN46 The resulting total of IFR funds requested for the rate year amount to $14.9 million ($1 million for meter replacements and $13.9 million for other IFR expenditures.)

FN46.*Id*. at 12-13.

Mr. Edge increased the IFR funding by $2,000,000 to fund improvements to the treatment facility and the revised lead abatement program. In addition, a $35,000,000 borrowing from the Clean Water Finance Agency will flow through IFR. Finally, Mr. Edge indicated that $600,000 should be transferred to the AMR restricted account so that meter related items will come out of a single account. FN47

FN47.*Id*. at 13-15.

With regard to funding the proposed Strategic Planning Study, Mr. Edge explained that while the total funding requested was $150,000, he was posting the adjustment to an account which had a carry-over balance of $32,000 from the test year for a study that was to be completed then. Therefore, the net adjustment was $118,000. FN48

FN48.*Id*. at 17.

Regarding the proposed rate design in this case, Mr. Smith explained that he worked with Providence Water to perform cost allocations and develop cost based rates and charges. FN49 Mr. Smith indicated that he used the same approach in this case as had been used in previous Providence Water cases, or “a modified base/extra capacity approach in which costs are allocated to cost of service categories based on the type of service being provided and then to customer classes on the way in which each class demands service.” FN50 Mr. Smith noted that “with the exception of the costs to be recovered from public fire protection charges and wholesale customers, costs are allocated to each customer class based on the way in which the class contributes to the demand for base and excess capacity.” FN51 He indicated that consistent with the prior rate filing, costs are allocated to wholesale customers based on their proportionate share of total consumption without consideration to their demand characteristics. FN52

FN49. Providence Water Exhibit 7 (Pre-Filed Testimony of Harold J. Smith), p. 2.

FN50.*Id*. at 4.

FN51.*Id*. at 5.

FN52.*Id*. at 6.

In this case, rather than utilizing the “relatively common practice” of allocating costs to fire protection based on a theoretical maximum day and maximum hour demand that fire protection may place on a system, Mr. Smith reduced the demand component of the fire protection charge by 50 percent. FN53 The result of this adjustment is that half of the demand related costs would be recovered from the public fire protection charge paid by the Cities of Providence and Cranston and the Towns of Johnston and North Providence while the remaining half would be recovered from the retail consumption charge. Mr. Smith stated that the rationale was to ensure that tax-exempt water customers pay a portion of the for fire protection charges which they avoid as being tax-exempt institutions. FN54

FN53.*Id*.

FN54.*Id*.

Mr. Smith explained that, with the exception of fire protection and the new wholesale service charge, the rates are calculated in the same way they were in the previous rate case. Retail service charges are calculated from costs allocated to Meters & Services and from Billing & Collection costs utilizing the number of equivalent meters and the number of customer billings.[FN55] Commodity rates are calculated by dividing the total base and extra capacity costs allocated to each customer class by the projected rate year consumption of that customer class.[FN56]

FN55. *Id*.

FN56. *Id*. at 7.

Addressing proposed changes to the methodology of assessing wholesale customers, Mr. Smith explained that wholesale customers are only assessed a commodity charge whereas in this filing, Providence Water is proposing to implement a 25 percent service charge to be assessed to wholesale customers on a monthly basis based on their annual revenues. The remaining 75 percent of the revenues to be collected from wholesale customers would be divided by the customers' anticipated rate year volumes to calculate the charge per hcf.[FN57] The stated purpose for this change would be to help stabilize Providence Water's revenues while not imposing an "inordinate" burden on wholesale customers. He stated that if pro forma usage is consistent with projections, their costs should not differ from a commodity-only charge.[FN58]

FN57. *Id*.

FN58. *Id*. at 8.

III. KCWA's Pre-Filed Testimony

On July 18, 2007, KCWA filed the Direct Pre-Filed Testimony of Christopher P.N. Woodcock, its consultant. Mr. Woodcock concluded that a reasonable increase in revenues would be sixteen percent, with the increase to wholesale customers set at 19.6 percent.[FN59] Mr. Woodcock noted that several of the requests for funding of restricted accounts extend beyond the rate year, including Insurance and Chemicals. Mr. Woodcock indicated that because Providence Water has historically used the accounts for their designated purposes, he did not object, as long as sufficient oversight remains in place in the future.[FN60] Additionally, he believed that approving this approach would allow utilities to have sufficient funding to avoid the expense of rate cases as often and this approach should be adopted for other water utilities.[FN61]

FN59. KCWA Exhibit 1 (Pre-Filed Testimony of Christopher P.N. Woodcock), p. 4.

FN60. *Id*. at 5.

FN61. *Id*. at 5-6.

Mr. Woodcock proposed adjustments to Providence Water's City Service Expense, projected property taxes, regulatory expenses, purchased power, and operating revenue allowance. Addressing City Service Expense, Mr. Woodcock noted that while Mr. Bebyn had prepared a detailed analysis with which Mr. Woodcock generally agreed, he proposed several adjustments. He also expressed concern that the fringe benefits added to the labor costs of each City department were more than 72% of salaries, opining that this was a high level of fringe benefits.[FN62]

FN62. *Id*. At 10.

With regard to the development of the General Overhead ("O") allocation factor, Mr. Woodcock maintained that the numerator (Providence Water's expenses) should not include the City Service Expense where the equation was designed to determine the appropriate percentage for City Service Expense and to include it amounts to double counting of City Services. He also argued that the payment of property taxes does not require much involvement by most City Departments and should be excluded from Providence Water's operating costs when developing the "O" allocation factor. He further noted that Mr. Bebyn had only included one of the three enterprise funds in the overall City budget, and believed all three should be included. Finally, Mr. Woodcock argued that expenses covered by federal and state grants should not be backed out of the City budget for purposes of developing the "O" allocation factor. He concluded that the "O" allocation factor should be reduced to 6.51 percent.FN63

FN63.*Id*. at 6-8.

Reviewing specific departmental costs, Mr. Woodcock believed the City Council cost allocated to Providence Water was overstated and proposed applying half of the reduced “O” allocator, or 3.26 percent to the City Council and also to the City Council Administration budgets to derive the City Service costs.FN64 Similarly, because Providence Water has its own finance department, he indicated that while the City Finance Department provides some services to Providence Water, he recommended applying half of the reduced “O” allocator to the City Finance budget to derive the City Service costs. FN65 Mr. Woodcock also took issue with the tasks Mr. Bebyn utilized in developing his factor for the City Clerk's Department and recommended applying no more than half of the “O” allocation factor.FN66

FN64.*Id*. at 8-9.

FN65.*Id*. at 9.

FN66.*Id*. at 9-10.

Next, addressing Providence Water's increase in property taxes, Mr. Woodcock proposed using less than the maximum 5 percent increase based on past experience, but agreed with Mr. Edge's proposal to update the property tax requirements when more information becomes available.FN67 Mr. Woodcock proposed eliminating a $5,000 regulatory expense entitled “City Services” because the basis for the request was unclear.FN68 He eliminated the adjustment to the test year power costs on the basis that the power contract between Providence Water and Constellation New Energy provided for no rate increase in the rate year.FN69 Additionally, Mr. Woodcock proposed eliminating an adjustment reflecting reduced sales to Bristol County on the basis that it appears those reductions would not occur in the rate year. He also added back the under-billing to Johnston which resulted in a change to the four year average for Johnston, affecting the overall wholesale sales and revenues for the rate year.FN70

FN67.*Id*. at 10-11.

FN68.*Id*. at 11.

FN69.*Id*.

FN70.*Id*. at 11-12.

Addressing the requested 3.0 percent operating allowance, Mr. Woodcock expressed support, but proposed that 1.5 percent be unrestricted and used in the manner of the current 1.5 percent operating allowance while the remaining 1.5 percent should be restricted and used to cover reduced revenues as a result of reduced water sales. He proposed a procedure for Providence Water to follow in order to gain access to the restricted portion of the account.FN71

FN71.*Id*. at 12.

Turning to Providence Water's proposed cost allocations, Mr. Woodcock first noted that Providence Water did not provide an allowance for unaccounted for water in the allocations between retail and wholesale service. He also took issue with the allocation of costs associated with pumping stations, noting that certain pumping costs and related labor should not be associated with wholesale service.FN72 Next, he discussed the fact that in the past, the Commission has not allowed inclusion of all employee benefits in the allocation to the customer service charge in order to control the level of the charge. In this filing, Providence Water assigned employee benefits to the category in which the employees function. Therefore, because of the new reporting capabilities of Providence Water, Mr. Woodcock believed that the Commission approach should be revisited. Specifically, he suggested that within each functional area, the employee benefits and pension costs should be allocated in the same manner as salary and wage costs because he maintained that customer accounting pension and benefits are unrelated to wholesale sales.FN73

FN72.*Id*. at 13.

FN73.*Id*. at 14-16.

Mr. Woodcock proposed several changes to the calculation of allocation symbols based on updated information using the same methodology used in prior dockets. With regard to allocator A, which is used to allocate costs between retail and wholesale service based on sales, Mr. Woodcock maintained that Providence Water had not accounted for lost or unaccounted for water. Therefore, Mr. Woodcock performed several calculations in order to derive an updated allocator A which would take into account lost or unaccounted for water. However, he noted that while losses are typically associated with under-registering water meters as well as line losses, the parties have historically assigned the losses only between transmission losses (responsibility of wholesale and retail customers) and distribution losses (responsibility of retail customers only). He maintained that in the future, the Commission should recognize meter losses and service pipe losses as well.FN74

FN74.*Id*. at 16-17, 19.

Mr. Woodcock recalculated allocator F which is used to allocate some transmission and distribution costs, primarily those costs associated with pipes where it is unknown if the cost is related to transmission or distribution pipes in order to update the allocator based on usage and inch miles of pipe. He also recalculated allocators HM, HMC, and HOC which are used to allocate various transmission and distribution costs in order to account for updated information, but using the same methods used in prior dockets. FN75

FN75.*Id*. at 17-18.

Mr. Woodcock also adjusted allocators CRAN, K1, K2, and T which are derived from the allocation of investment or the net value of Providence Water's assets. He made an adjustment to the plant allocation by splitting transmission and distribution investment.FN76

FN76.*Id*. at 18.

With regard to allocators TD and N which are used to allocate distribution pipe costs (TD) and pumping costs (N), Mr. Woodcock indicated that in Providence Water's assignment of costs to customer classes, no base or average use costs were assigned to fire protection. As a result, according to Mr. Woodcock, the amount of water used for fire fighting was not considered in the allocation of line items with these costs; only the peak demand portion was considered. Mr. Woodcock opined that this symbol must be modified to reflect the fact that some base water use that goes through pipes and pumps goes to fire services. Therefore, he included 1% for fire protection and adjusted the other symbols accordingly. FN77

FN77.*Id*. at 18-19.

Mr. Woodcock proposed several new allocators to arguably derive a more equitable allocation of costs and to properly recognize the layout and operation of the Providence Water system. He proposed allocators DY, HMY, and YY to remove all benefit costs assigned to billing and meters within the Transmission & Distribution, Customer Accounts, and Administration functions. He proposed allocator NO to assign the pumping O&M costs to reflect the fact that the Raw Water Pumping Station costs are not part of those unlike allocator N which he indicated assumes that the Raw Water Pumping Station is a part of the pumping operating costs. He proposed allocator NP to allocate the pump station power costs in place of allocator N that includes the Raw Water Station from this cost maintaining that it is a more equitable calculation based on actual costs.FN78

FN78.*Id*. at 20-21.

Mr. Woodcock indicated that allocator WC, proposed to allocate the capital costs associated with the Western Cranston system, have nothing to do with the provision of wholesale service. He noted that while the pro forma costs are minimal ($62,069), he also argued that if impact fees or future fund balances are insufficient to cover projected investment, wholesale customers should not be required to contribute to this retail only investment.FN79

FN79.*Id*. at 21.

Mr. Woodcock indicated that that pumping costs should continue to be recognized differently because Providence Water's system includes some costs that are shared by all customers and some costs that are only for retail customers. The wholesale customers distribute the water to their own individual customers rather than from Providence Water. Therefore, wholesale customers should not have to pay for retail service they do not receive including those of some of Providence Water's pumping stations. As such, he proposed estimating labor and benefit costs for the operation of Providence Water's pumping stations and moving them from treatment to pumping operating costs for ratemaking. He also promoted the adoption of new pumping allocators to reflect the fact that the Raw Water Pumping Station costs are not part of the Pumping O&M expenses.FN80

FN80.*Id*. at 21-22.

Further addressing the reasons Mr. Woodcock advocated elimination of the COMM Y allocator which he believed was adopted to move costs from the billing or customer service charge to the metered rate, Mr. Woodcock argued that the continued use of this allocator results in the assignment of costs related to customer service employee benefit costs to wholesale customers only.FN81 He maintained that the adoption of the new symbols he recommended for the Customer Service, Transmission & Distribution, Administrative, and Insurance functions will assure that the cost of benefits continue to be removed from the retail customer service charges to the metered rates while eliminating the inequities of allocating such costs to wholesale customers. FN82 Additionally, for Water Treatment O&M, Transmission & Distribution, Customer Accounts, and Administration he replaced allocator COMM Y with AA for the allocation of employee benefits consistent with Mr. Smith's agreement that employee related costs should be allocated in the same manner as the salaries and wages for that function.FN83

FN81.*Id*. at 22-23.

FN82.*Id*. at 23.

FN83.*Id*. at 24.

Mr. Woodcock's final cost allocation adjustments were related to the manner in which specific line items are allocated. With regard to pumping operating costs, he indicated he had taken some of the expenses related to salaries and benefits from treatment and moved them to operating costs where they are properly reflected. He maintained that these adjustments did not change the overall costs but rather, moved some salary and benefit costs from one area (treatment) to another (pumping) to better reflect actual conditions.FN84 He proposed using his recommended new allocator NO for the pumping operating costs and allocator NP for the power related pumping costs.FN85 Mr. Woodcock noted that the Western Cranston portion of the system did not relate to wholesale service, and he recommended that the Western Cranston capital fund should only be allocated to retail customers.

FN84.*Id*. at 23-24.

FN85.*Id*. at 24.

Turning to rate design issues, Mr. Woodcock noted that Providence Water proposed two significant rate design changes: (1) a fixed wholesale charge and (2) a reduced public fire service charge. In addition to these changes, he indicated that Providence Water proposed retail rates that are based on peaking factors for various retail customers, something that does not affect wholesale customers in this docket, but which could have an effect on subsequent rate cases.FN86

FN86.*Id*. at 26.

Addressing the proposed fixed charge to wholesale customers, Mr. Woodcock indicated that wholesale customers oppose the proposal because wholesale water sales will not be exactly as projected by Providence Water and there will either be a loss or a gain from this class of customers. He agreed that revenue stability is a reasonable goal of a utility, but he argued that Providence Water was not attempting to stabilize the right rates or revenues from the right customers. For example, he stated that Providence Water's proposal to move fixed hydrant revenues to variable use based revenues was contrary to its goal of stabilizing revenues. FN87 Elaborating, Mr. Woodcock noted that review of the adjusted historic retail and wholesale sales shows that the retail customers exhibit a much greater variation from the average than do the wholesale customers.

He indicated that in nearly every year, the retail difference from the average is twice that of the wholesale customers. Therefore, he concluded that the variation in revenues or instability is caused more by retail customers than wholesale customers. Noting that Providence Water's proposal would recover less than 20 percent of the retail costs from fixed retail charges, Mr. Woodcock questioned why Providence Water believed a higher percentage of fixed revenues from a more stable, but smaller revenue base made sense.[FN88] Furthermore, he argued that proposing 50% of the fixed fire protection revenue be transferred to the most unstable source, retail metered rates, is inconsistent with the goal of revenue stability.[FN89]

FN87.*Id*.

FN88.*Id*. at 27.

FN89.*Id*.

Elaborating on the proposed reduction in fire charges, Mr. Woodcock agreed with Mr. Smith that there are tax exempt properties that avoid paying their share of fire protection costs, but argued that switching the fire protection costs to water use may not be any more equitable because it assumes that the level of fire protection is proportional to water use rather than property value, and Mr. Woodcock opined that the evidence did not support that assumption.[FN90]

FN90.*Id*. at 28.

Discussing the peaking factors for various classes of customers, Mr. Woodcock agreed that revisions in methodology are accepted from time to time, but expressed concern that the factors presented by Providence Water are not appropriate because these factors are presented as coincident peaks for each customer class, which is the peak demand by each class at the time of the system peak. He believed the correct methodology would be to use non-coincident peaks. Regardless, he argued that the peaking factors proposed by Providence Water were incorrect.[FN91]

FN91.*Id*. at 28-29.

IV. Division's Pre-Filed Testimony

On July 18, 2007, the Division of Public Utilities and Carriers ("Division") filed the Direct Pre-Filed Testimony of Thomas Catlin, its consultant on revenue requirement and Jerome Mierzwa, its consultant on cost allocation. Mr. Catlin recommended a total cost of service of $58,710,135, necessitating a revenue increase of $7,389,179 or 12.6 percent.[FN92]

FN92. Division Exhibit 1 (Pre-Filed Testimony of Thomas Catlin), Schedule TSC-1.

In arriving at his revenue requirement, Mr. Catlin made adjustments to rate year revenue to reflect a current count of the number of retail and private fire service customers and to properly account for changes to wholesale sales and associated variable costs.[FN93] He proposed adjustments to salaries and wages in order to account for employee vacancies that normally develop during any given year.[FN94] He made adjustments to operating expenses and to the IFR and CIP expenses to properly account for capitalized expenses in accordance with the Commission's Order in Docket No. 3446.[FN95] After reviewing Providence Water's electric supply contract, Mr. Catlin made a $543,699 downward adjustment to Providence Water's proposal.[FN96] He proposed setting the PUC assessment at the test year level on the basis that the 2007 assessment was slightly less than the 2006 assessment. This resulted in a $14,008 reduction to Providence Water's proposal.[FN97] Mr. Catlin also made two adjustments to the Contractual Services - Engineer and Legal Accounts on the basis that Providence Water's request was for increased costs that did not represent a normal recurring costs. This resulted in a $73,185 reduction to Providence Water's request.[FN98] Mr. Catlin did accept Providence Water's proposed chemical expense on the basis that even though updated bid prices showed those costs to be increasing, there should be sufficient funds in the restricted account to absorb those increases through FY 2009 and possibly 2010.[FN99] Additionally, Mr. Catlin identified a concern with the methodology Mr. Edge used to forecast property tax expense for the rate year, but relying on Mr. Edge's representation that he would adjust the request when updated property tax bills become available, Mr. Catlin made no adjustment, instead indicating that he would reevaluate the request after the rebuttal phase of the case.FN100

FN93.*Id*. at 5-6, 10-11.

FN94.*Id*. at 7-8.

FN95.*Id*.

FN96.*Id*. at 9-10.

FN97.*Id*. at 10-11.

FN98.*Id*. at 11-12.

FN99.*Id*. at 12-13.

FN100.*Id*. at 16.

Addressing Providence Water's request to reimburse the City of Providence for the cost of health insurance provided for retirees during the period 1997 through 2005, Mr. Catlin noted that Providence Water was requesting retroactive recovery of costs applicable to prior periods for which it failed to seek timely recovery. He indicated that because Providence Water is not an investor owned utility and the City of Providence is in financial difficulty, he would not oppose recovery. He did note that during discovery, Providence Water reduced the recoverable amount to $1,489,081 and Mr. Catlin proposed a six year recovery period instead of the five and one-half years requested by Providence Water.FN101 Furthermore, with regard to the requirement under GASB 43/45 requiring municipalities to recognize their future liabilities for postretirement benefits, Mr. Catlin accepted Providence Water's calculation which was based on a 50 percent contribution level, designed to match the City of Providence's contribution level. However, he recommended that in the event the City does not fund its portion at the 50 percent level, Providence Water only fund the same percentage and deposit the remainder in a restricted account.FN102

FN101.*Id*. at 8-9.

FN102.*Id*. at 13-14.

Addressing Providence Water's claim for City Service Expense, Mr. Catlin indicated that he was concerned that when developing the General Overhead allocator, Mr. Bebyn did not include all enterprise funds of the City of Providence in the City's overall expenses. The result was a $5,597 reduction to the City Service Expense which Mr. Catlin assumed Mr. Bebyn would make as part of his rebuttal testimony. Mr. Catlin also identified a $5,000 City Service expense included in the estimated rate case expense, but was unable to identify the nature of the expense and recommended it not be included without such detail.FN103

FN103.*Id*. at 14-15.

Finally, discussing Providence Water's proposed 3.0 percent Operating Revenue Allowance, Mr. Catlin recommended the Commission continue to set it at 1.5 percent. Mr. Catlin noted that Providence Water had not only made adjustments for known and measurable costs, but also for other expenses by applying an inflationary factor. He also noted that recent Commission decisions appear to show a policy of reducing operating revenue allowances rather than increasing them. He recommended that if the Commission decides to increase the Operating Revenue Allowance, it cut the inflationary factor that is currently included in Providence Water's projections. He also recommended that restricted fund expenditures for capital related items be excluded from the calculation of the Operating Revenue Allowance if it is increased to 3.0 percent. Such an adjustment would decrease Providence Water's request by approximately $500,000. Allowing only 1.5 percent would decrease Providence Water's request by half, or approximately $850,000.FN104

FN104.*Id*. at 16-19.

In addressing the cost allocations in Providence Water's filing, Mr. Mierzwa noted that Providence Water had used the base-extra capacity method, one of the two generally accepted methods for allocating costs to customer classes. Under this method, investment and costs are first classified into four primary functional cost categories: base or average capacity, extra capacity, customer and direct fire protection. The costs within the four primary functional costs are then further divided and allocated.FN105 Mr. Mierzwa proposed several changes to Providence Water's cost allocations used in its cost of service study including: (1) rejecting Providence Water's proposal to reduce the demand component of fire protection service by 50 percent; (2) revising the allocation of transmission and distribution mains investment; (3) updating several cost allocation factors from those initially developed in Docket No. 3163, Providence Water's most recent cost of service study with cost allocations; (4) modifying the allocation of miscellaneous revenue; (5) recognizing the costs associated with lost and unaccounted-for water; and (6) revising the allocation of certain source of supply operation and maintenance expenses. Mr. Mierzwa also addressed Providence Water's allocation of pension and benefits expenses.FN106 However, because he was still waiting for some updated information from Providence Water, he did not incorporate the Division's revenue requirement adjustments into his study, but would do so in surrebuttal.FN107

FN105. Division Exhibit 2 (Pre-Filed Testimony of Jerome Mierzwa), p. 4.

FN106. *Id.* at 5.

FN107. *Id.* at 13.

First addressing the fire protection demand component, Mr. Mierzwa explained that in Docket No. 3163, certain costs were allocated to fire protection service based on the maximum day and maximum hour demands that fire protection could potentially place on the Providence Water system. In this case, Providence Water reduced the maximum day and maximum hour demands assigned to fire protection service by 50 percent. The result of this proposal is to collect half of the demand costs from fire protection and half from retail volumetric charges rather than 100 percent from fire protection as was allowed in Docket No. 3163.FN108

FN108. *Id.* at 6.

With regard to this proposal, Mr. Mierzwa recommended it be rejected for several reasons. First, that it also reduces demand to private fire protection service, thereby requiring general water service customers to bear a portion of those costs. Second, with regard to Providence Water's argument that tax exempt entities are unfairly benefiting from the system, Mr. Mierzwa stated that Providence Water does not know the usage of tax exempt customers on its systems and as a result, cannot determine the extent to which its proposal will provide for the recovery of public fire protection costs from tax exempt customers. Third, IFR costs are not recovered through fire protection rates, but through volumetric rates, thus already reducing the costs associated with fire protection which need to be recovered from other customers. Fourth, the recovery of 50 percent of the demand charge through volumetric rates rather than a fixed fire protection charge is inconsistent with Providence Water's desire for revenue stability. Finally, Mr. Mierzwa disagreed with Providence Water's assertion that recovery of fire protection services through usage rates provide for a better match between benefits and costs than the current procedures, providing the example of a commercial warehouse with high-cost inventory and very little water usage. He explained that this customer receives a significant benefit from fire protection service but would avoid paying for a significant portion of this benefit under Providence Water's proposal. Another customer with high water usage because of a pool or irrigation needs, but a lower tax rate would contribute disproportionately to the recovery of fire protection service costs.FN109

FN109. *Id.* at 6-8.

Second, addressing Providence Water's allocation of transmission and distribution ("T&D"), Mr. Mierzwa noted that none of the investment had been allocated to wholesale customers despite the fact that transmission mains are used to serve those customers. Because the cost of service study in this docket did not separately identify transmission and distribution mains investment, Mr. Mierzwa prepared an inch-mile study to estimate Providence Water's transmission investment. Because his study indicated that 41.42 percent of Providence Water's mains investment was transmission related, he allocated this portion of Providence Water's total T&D

mains investment to wholesale customers based on annual consumption.FN110

FN110.*Id*. at 8-9.

Third, Mr. Mierzwa proposed updating factors to allocate T&D salaries and wages (Factor HM), T&D contractual services (Factors HOC and HM), and T&D operation and maintenance expenses (Factor F). He noted that the values of the factors were based on fiscal year 1999 data. Through discovery, Mr. Mierzwa requested that Providence Water update the detailed analysis performed in Docket No. 3163 and Providence Water did so, utilizing fiscal year 2006 data. Mr. Mierzwa noted that costs can change from year to year and as such, a multi-year average would be appropriate. He stated that he is awaiting detailed analyses from Providence Water for fiscal years 2004 and 2005. Therefore, with the exception of the T&D operation and maintenance expense factor, he would make the adjustments in his surrebuttal testimony. With regard to the T&D operation and maintenance expense factor, Mr. Mierzwa proposed updating the allocation for wholesale customers based on his updated inch-mile analysis.FN111

FN111.*Id*. at 9-10.

Fourth, with regard to Miscellaneous Revenue, Mr. Mierzwa noted that it had been credited to cost function based on labor-related O&M expenses where, in his opinion, it should have been allocated to function consistent with the source of revenue. He indicated he would address the issue further in his surrebuttal testimony.FN112

FN112.*Id*. at 10-11.

Fifth, addressing lost and unaccounted-for water, Mr. Mierzwa defined it as the difference between metered production and metered consumption which can result from things like leaks and inaccurate meters. He noted that because Providence Water did not separate out the differences for the distribution and transmission portions of the system, under its cost allocation, wholesale customers would bear some responsibility for the distribution system, something that is incorrect in light of the fact that the distribution system does not serve wholesale customers. He noted that Providence Water had agreed with his position and he adjusted the study based on the actual average of lost and unaccounted-for water for the period fiscal years 2003 through 2006, with an additional adjustment to account for an under-registering meter in Johnston.FN113

FN113.*Id*. at 11.

Sixth, addressing the allocation of source of supply investment to the functional category, Mr. Mierzwa indicated that all source of supply investment should be allocated based on annual consumption. He noted that Providence Water had allocated Land and Land Rights, Structures and Improvements and Collecting and Impounding Reservoirs in such a manner, but not the Supply Mains and Other Water Source Plant. He opined that this may have been a clerical error.FN114

FN114.*Id*. at 12.

Finally, addressing the allocation of pensions and benefits, Mr. Mierzwa noted that Providence Water had allocated pension and benefits to source of supply, water treatment, T&D, customer accounting and administrative and general O&M categories, while pension and benefits expenses within each O&M category were allocated to functional category based on total wages, with those costs allocated to meters and services and billing and collections allocated to other retail cost functions using Factor Comm Y in order to follow past Commission directives to limit the increases in service charges. He maintained that because these costs are labor-related, they would ordinarily be allocated without the additional reallocation of costs associated with meters and service and billing and collections, but noted that not allocating the costs based on Factor Comm Y would result in a 102 percent increase in the quarterly service charge.FN115

FN115.*Id*. at 12-13.

V. Providence Water's Rebuttal Testimony

On August 21, 2007, Providence Water submitted the

Rebuttal Testimony of Ms. Marchand, Ms. Bondarevskis, Mr. Gadoury, Mr. Edge and Mr. Smith. In addition to responding to the positions of the Division and KCWA, Providence Water provided testimony regarding rate treatment of a tax refund it received from the City of Cranston to settle a property tax dispute.

Ms. Marchand explained that on August 15, 2007, the Providence Water Supply Board voted to accept a settlement agreement with the City of Cranston for contested taxes. The total due to Providence Water from the City of Cranston was $1,508,362 plus interest of $216.77 per day from August 16, 2007 until payment was made. Ms. Marchand proposed that the money received be placed in a restricted account to fund further expenses resulting from contesting property tax bill and to cover higher than expected property tax increases. Ms. Marchand implied that this treatment of the tax refund would allow Providence Water to agree with the Division's recommended reduction of engineering and contractual legal expense.[FN116]

FN116. Providence Water Ex. 12 (Rebuttal Testimony of Pamela Marchand), pp. 2-3.

Addressing the parties' positions regarding Providence Water's three percent operating revenue allowance, Ms. Marchand noted that KCWA agreed with the request but recommended part of the amount be restricted. Ms. Marchand proposed that since restricted funds account for 41 percent of total expenses, that 40 percent of the 3.0 percent allowance, or 1.2 percent, be allocated to a separate restricted account to ensure funding of the restricted accounts when there is a shortfall in revenues. The remaining 1.8 percent operating revenue allowance would be unrestricted.[FN117] With regard to the Division's position, Ms. Marchand noted that Mr. Catlin indicated that if Providence Water was allowed three percent, then the proposed inflationary factor should not be considered. Ms. Marchand argued that inflation had been higher than the proposed factor for the prior two years. She also did not believe the operating revenue allowance should be restricted to fluctuating expenses, but also be used for unanticipated expenses.[FN118]

FN117. *Id*.

FN118. *Id*. at 4-5.

Ms. Bondarevskis provided Providence Water's response to the parties' positions on various expense items. Ms. Bondarevskis explained that Providence Water agreed to Mr. Catlin's recalculation of the past retiree health care amount and revised repayment period. She indicated that Providence Water would also agree to Mr. Catlin's adjustment to the Contract Service - Legal and Engineering if Providence Water is allowed to charge all rate year and future expenses for defending property tax bills to a restricted account set up from the Cranston property tax refund.[FN119]

FN119. Providence Water Exhibit 11 (Rebuttal Testimony of Jeanne Bondarevskis), pp. 1, 3-4.

However, Ms. Bondarevskis disagreed with Mr. Catlin's proposed adjustment to the PUC Assessment portion of Regulatory Commission Expense. In support of Providence Water's position, she prepared a schedule of the PUC Assessment History from FY 2002 through FY 2007. She noted that based on the methodology for calculating the PUC assessment, she expected the FY 2008 assessment to be higher than the test year assessment. The result of her calculation was a $4,600 increase over what was presented in Providence Water's direct testimony.[FN120] Addressing a line item that was questioned relative to the Rate Case Expense, entitled City Services, Ms. Bondarevskis explained that a separate $5,000 line item was the bid price for B&E Consulting to prepare the City Service analysis and she maintained the expenses should remain part of the rate filing costs.[FN121] Finally, Ms. Bondarevskis noted that in the process of responding to Commission data request 3-15, Providence Water noticed that it had contributed 90 percent of the actuarial amount to the pension fund for FY 2004 while the City of Providence had contributed 86 percent. Therefore, she indicated that Providence Water will make a $99,746 adjustment to its FY 2008 contribution in order to adjust for the difference between Providence Water's contribution and the City's.[FN122]

FN120. *Id*. at 2-3.

FN121. *Id*. at 3.

FN122.*Id*. at 4-5.

Mr. Gadoury provided testimony in response to the Division's submission of the Woodard & Curran report relative to the filter effluent piping improvements associated with the filter upgrade project. He noted that Woodard & Curran agreed with the necessity of the project, but had suggestions regarding methodology. Mr. Gadoury expressed concerns with Woodard & Curran's proposals on the basis of cost and feasibility given the current structural conditions. Therefore, Mr. Gadoury concluded that based on his experience as a Registered Professional Engineer, he concurred with the report of the Maquire Group, his design consultant, that rejected the comments and suggestions of the Woodard & Curran report.FN123

FN123. Providence Water Exhibit 8 (Rebuttal Testimony of Paul Gadoury), pp. 1-6.

Mr. Edge accepted the Division's adjustments to Wholesale Water Sales, Capital Reimbursement, and to the City Services overhead allocator to account for other enterprise funds of the City.FN124The City Services overhead allocator was now proposed at 8.08 percent. Mr. Edge also agreed with Mr. Catlin's proposal to fund its GASB 43/45 requirement for future retiree health care liability at the same percentage as the City of Providence, with any remainder of that which is already built into rates deposited into a restricted account. FN125 Mr. Edge noted that Mr. Catlin made no adjustment to Providence Water's projected chemical costs despite the fact that those costs have increased since Providence Water's initial filing. However, he agreed with Mr. Catlin that there should be enough in the restricted chemical account to offset the increased costs. FN126

FN124. Providence Water Exhibit 10 (Rebuttal Testimony of Walter Edge), pp 1-2.

FN125.*Id*. at 5.

FN126.*Id*. at 5-6.

Mr. Edge conceded that his original percentage increase for purchased power expense was too high, but believed Mr. Catlin's was too low. He conceded that the purchased power contract between Providence Water and Constellation, Inc., New England would provide savings in the test year, but not necessarily during the interim and rate years. He provided a schedule to show increased purchased power expense during the interim year and based on that schedule, proposed a 1.05 percent in the electric purchased power expense applied to the interim year actual electric cost and a 3.75 percent increase in the purchased gas cost applied to the interim year actual gas cost.FN127Mr. Edge noted that Mr. Catlin had not made any adjustments to the rate year property tax projection, but was awaiting actual FY 2008 property tax bills. After receiving those bills and increasing them by 1.55 percent to address the projected increases from July 1, 2008 through December 31, 2008, Mr. Edge updated his projection for the rate year. His new projection of $6,325,081 represented a $245,711 reduction from his initial projection.FN128

FN127.*Id*. at 3-4.

FN128.*Id*. at 4-5.

Mr. Smith provided rebuttal testimony to address: (1) the allocation of fire protection demand; (2) peaking factors; (3) the wholesale fixed charge proposal; and (4) various cost allocations.FN129With regard to the proposed fire protection demand, Mr. Smith indicated that because of recent Commission decisions not to increase private fire connection charges Providence Water was attempting to find another equitable manner of recovering fire protection costs. He argued that the testimony of the Division and KCWA witnesses did not prove the proposal to be inequitable and that the previous methodology was not equitable because it did not collect fire protection charges from tax exempt entities.FN130

FN129. Providence Water Exhibit 9 (Rebuttal Testimony of Harold Smith), p. 1.

FN130.*Id*. at 2.

Mr. Smith disagreed with Mr. Woodcock's position that the peaking factors Providence Water used were not reasonable. He agreed that the methodology was not ideal, but provided a reasonable allocation of costs among retail customer classes. He also recognized that the peaking factors do not take into account whether a wholesale customer has storage capabilities. However, he explained that wholesale customers do not currently share in maximum day and maximum hour costs, but are allocated costs based only on their relative share of average day capacity. Therefore, they are basically allocated a share of maximum day and maximum hour costs based on the average of the system. This is why the peaking factors for wholesale customers tend to approximate those of the entire system.FN131

FN131.*Id*. at 3.

With regard to Mr. Woodcock's assertion that the fixed wholesale charge would provide Providence Water with lower revenues than it would realize under the current consumption based model if wholesale water usage increased, Mr. Smith indicated that Providence Water believes the benefits of stabilizing wholesale revenues outweigh the possibility of reduced revenues. He noted that Mr. Woodcock testified that wholesale consumption has historically been close to historical average. Responding to Mr. Woodcock's argument that it was incongruous to apply a wholesale fixed charge while decreasing fire protection fixed charges, Mr. Smith argued that wholesale revenues make up 25 percent of revenues versus 6 percent for fire protection revenues, and therefore, under the proposal, a larger portion of revenues would be derived from fixed charges than under the previous rate structure.FN132

FN132.*Id*. at 3-4.

Addressing cost allocations, Mr. Smith agreed to include unaccounted for water in the cost allocation, affecting Allocation Factor A. He updated Allocation Factor F using June 30, 2007 data. He proposed updating Allocation Factors HM, HMC and HOC based on multiyear data. Finally, Mr. Smith agreed with Mr. Woodcock's proposal to reallocate benefit and pension expenses to Base for Transmission & Distribution, and Administration in order to more equitably distribute those costs.FN133

FN133.*Id*. at 5-6.

VI. Kent County Water Authority's Surrebuttal

On September 7, 2007, KCWA submitted the pre-filed Surrebuttal testimony of Christopher Woodcock. Mr. Woodcock noted that there were three remaining issues in dispute between the parties related to revenue requirements: (1) the disposition of the Cranston property tax refund and associated expenses claimed for tax case litigation; (2) the cost of City Services; and (3) the level of operating revenue allowance and how it might be used or restricted.FN134

FN134. KCWA Exhibit 2 (Surrebuttal Testimony of Christopher Woodcock), p. 2.

First, with regard to the Cranston property tax refund, Mr. Woodcock explained that there appeared to be an agreement among the parties to remove the legal and engineering expenses associated with the tax litigation from the Administrative General and Legal Contract Services line items and to utilize a portion of the tax refund for those costs. He indicated that $375,000 would be returned to ratepayers for the next three years while the balance of the tax refund would be restricted for legal and engineering costs related to the tax litigation. He did suggest five conditions for the restricted account: (1) Providence Water should be required to report activity in the account to all parties to this docket on a regular basis; (2) that funds only be used for tax litigation support and not for paying increased property taxes; (3) that the amounts returned to ratepayers should be based on the allocation of Cranston property taxes decided upon by the Commission; (4) if after three years, there is any money remaining in the account, it is to be held for disbursement back to ratepayers in proportion to the current tax allocation or reconsideration by the Commission with notification to all parties in this docket; and (5) any additional tax settlement/refund dollars must be deposited to this account and not used for any other purpose.FN135

FN135.*Id*. at 2-3.

Second, with regard to City Service expense, Mr.

Woodcock indicated that he had not changed the position he took in his direct testimony. While noting that Providence Water had agreed to include other enterprise funds in its calculations, he continued to express concern with three issues: (1) a purported double counting of City Services; (2) the inclusion of over $6 million of property taxes as water expense that he maintained have no bearing on the services provided by most City Departments; and (3) the exclusion of expenses covered by external sources of funding. Mr. Woodcock argued that Providence Water had addressed none of his concerns related to support for the allocators used for City Council, City Council Administration, Finance Department and City Clerk's office.FN136 He indicated that his position was not to deny any cost allocation to these departments, but rather, he had "recommended that most of the offices where there is no apparent service or where the service is a duplication of internal Providence Water functions be funded at only half [of his] revised "O" allocator."FN137

FN136.*Id*. at 3-5.

FN137.*Id*. at 5.

Third, with regard to the operating revenue allowance, Mr. Woodcock testified that KCWA continued to support an increase from 1.5 percent to 3.0 percent of total expenses, with a portion being unrestricted and the balance restricted for use if there were a revenue shortfall. FN138

FN138.*Id*. at 6.

Turning to cost allocation issues, Mr. Woodcock addressed the calculation of unaccounted for water, expressing concern that the reported amounts for unaccounted for water were not based on actual meter readings. He noted that Providence Water had indicated a willingness to provide those numbers. He also indicated that KCWA disagreed with the amount Providence Water and the Division had used to calculate unaccounted for water. He noted that the four year average used by the witnesses included under registered use by Johnston, thus affecting the accuracy of the calculations. He proposed reducing the reported unaccounted for water by the Johnston under registration because he maintained the water is now "accounted for."FN139

FN139.*Id*. at 6-8.

Finally, with regard to unaccounted for water, Mr. Woodcock proposed not using the inch-foot method of allocating unaccounted for water because he maintained it assigns too large a portion of water losses to transmission pipes and fails to recognize losses on the retail side. He recognized that the inch-foot method has been the accepted methodology, but argued that as new information becomes available, it should be considered by the Commission. In support of his argument, Mr. Woodcock indicated that since the filing of his direct testimony he had performed some research and he referenced an American Water Works Association Water Loss Task Force report which concluded that "the annual volume of unavoidable losses is a function of the length of water mains, number of service connections, and length of private service connections. Most notably, the size or diameter of the pipe is not one of the elements considered - it is simply the length of the pipe." FN140 Mr. Woodcock noted that while he raised this issue, he had not made an adjustment in this case which would assign more use to retail customers, but wanted the Commission to recognize that "the allocation of unaccounted for water should reflect the length of service pipe, including service connections, and not the inch-feet of pipe excluding service connections" and he believed such related adjustments should be considered in the next docket.FN141

FN140.*Id*. at 8-9.

FN141.*Id*. at 9-11.

Next, addressing Providence Water's proposal to apply a fixed wholesale charge of 25% rather than using actual sales, KCWA maintained that this was not a fair revision to the tariff. Mr. Woodcock argued that while the proposal would increase revenue stability for Providence Water, it would only be on the wholesale side, particularly when Providence Water was proposing a reduction in the demand charge for fire protection. He also argued that if the fixed charge is based on a year of high wholesale consumption, the wholesale customers would be overcharged in lower consumption years. Finally, he noted that the State of Rhode Island appears to be very interested in conservation and this proposal is not in alignment with that goal.FN142

FN142.*Id*. at 11-13.

Mr. Woodcock also addressed four other areas of concern, including: (1) the classification of pumping labor and allocation of those costs; (2) the recognition that the raw water pump station should not be considered in the allocation of pumping operating costs, particularly power; (3) the allocation of benefits; and (4) the allocation of capital other power production within treatment. FN143

FN143.*Id*. at 13-14.

Mr. Woodcock stated that under what had been filed, the pumping stations included retail only or distribution pump stations as well as pump stations where some costs should be shared by wholesale customers. He indicated that it would be incorrect to allocate the pumping costs the same as the treatment costs because some of the pumping costs are unrelated to service to wholesale customers. He noted that in the past, these different costs have been recognized in rate setting for Providence Water and that this should continue.FN144

FN144.*Id*. at 14.

According to Mr. Woodcock, his reclassification of labor and benefit costs to pumping allows for the proper allocation of retail only costs to retail service and joint costs to both wholesale and retail customers. Therefore, under his proposal, he maintained that wholesale customers not be allocated costs that have nothing to do with service that is provided to them.FN145

FN145.*Id*. at 15.

He indicated that because the pumping O&M costs do not include the raw water pumping station it was necessary to develop a new allocation symbol that only included the pumping stations in question and excluded the raw water pump station. He split the costs between retail and wholesale as in prior dockets, but excluded the raw water pumping station. Further, he stated, because the pumping power costs do not include the raw water pumping station it was also necessary to develop a new allocation symbol for pumping power.FN146

FN146.*Id*.

Addressing the differences among the parties regarding the allocation of benefits, Mr. Woodcock stated that in prior dockets the employee benefits had been included as a separate line item expense under Administration. He disagreed with Mr. Mierzwa's allocation, but believed that Mr. Smith's updated cost allocation properly allocated the employee benefit costs within each O&M cost category based on the labor allocation within that category. Mr. Woodcock stated that this is correct because the benefits are related to the labor costs and should be allocated the same way. Mr. Woodcock did disagree with the fact that Mr. Smith did not move the allocation of any benefits from the billing and meter & service categories which resulted in Mr. Smith calculating a significant increase in the service charges.FN147

FN147.*Id*. at 15-16.

Mr. Woodcock concluded that the Commission's prior directive to not allocate benefits to the service charge can be accomplished along with the individual allocation of benefits within each cost category by developing a new allocation for each category's benefits that moves the billing and the meter & service pieces to the retail base charge. According to Mr. Woodcock, these new allocation symbols keep the benefits allocated properly within each category and preserve the Commission's past desire to minimize the retail service charges.FN148

FN148.*Id*. at 16.

Addressing the allocation of capital other power production within treatment, Mr. Wooodcock noted that he had allocated the Other Power Production Equipment using allocation symbol A upon the belief that this equipment is related to the overall production of water and that it should not be allocated like the retail and distribution pumping stations as Mr. Mierzwa has allocated it. He indicated that Mr. Smith's allocation of this capital expense was consistent with the method he had used. He stated that while Mr. Mierzwa's allocation is beneficial to the wholesale customers, this capital item only includes supply pumping and that the method used by Mr. Smith is more correct.FN149

FN149.*Id*.

Addressing the proposal to reduce fire protection demand, Mr. Woodcock stated that in general, rates should be based on the cost to provide service and that Providence Water had not provided a valid reason why the fire protection charges should be reduced by 50 percent.FN150 The result of Mr. Woodcock's proposed adjustments would allow Providence Water a 14.2 percent increase in rate revenues or $7,092,248, with an increase to wholesale rates of 13.8 percent to $1,406.42 per million gallons with no fixed charge.FN151

FN150.*Id*.

FN151.*Id*. at 18.

VII. Division's Surrebuttal

On September 7, 2007, the Division submitted the prefiled Surrebuttal testimony of Thomas Catlin and Jerome Mierzwa.FN152 The Division also submitted the second engineering report of Helen Gordon, in response to the Maguire Group's comments included with Providence Water's Rebuttal testimony. The Division's attorney noted that the engineering reviews have been presented "for the purpose of demonstrating that an independent firm has concluded that the significant upgrades proposed by Providence [Water] to its treatment facility are necessary."FN153 The level of professional disagreement over one design aspect, according to the Division's attorney, did not rise to the level where additional Division involvement appears necessary.FN154

FN152. On September 10, 2007, the Division submitted corrected schedules. On September 12, 2007, the Division provided a full copy of Mr. Mierzwa's Surrebuttal Testimony with Corrected Exhibits which was marked Division Exhibit 5.

FN153. Filing Letter to Luly Massaro, dated 9/6/07, p.2, referencing Division Exhibit 6.

FN154.*Id*.

In his testimony, Mr. Catlin noted that Providence Water had accepted his adjustments to wholesale water revenue, capital reimbursement, retiree health expense and City Service expense. Mr. Catlin indicated that property tax expense updates and purchased power cost revisions appeared reasonable. In addition, Mr. Catlin accepted Ms. Bondarevskis' adjustment to address a recent year where Providence Water's contribution to the City pension was in excess of that which was contributed by the City of Providence.FN155 Finally, after a review of additional information from Providence Water, Mr. Catlin is no longer proposing an adjustment to regulatory commission expense or rate case expense.FN156

FN155. Division Exhibit 4 (Surrebuttal Testimony of Thomas Catlin), pp. 1-2.

FN156.*Id*. at 5.

Addressing the first remaining item in dispute, treatment of the City of Cranston tax refund, which would provide a refund of $1,508,362 plus interest to Providence Water, Mr. Catlin did not agree that the creation of a reserve fund with a balance of $1.5 million to cover future property tax litigation costs would be reasonable.FN157 Noting that the total spending on these types of matters over the past five years has been approximately $550,000, even with projected increases in litigation related to the Scituate tax dispute, Mr. Catlin did not believe there was evidence that the costs would approach three times that amount. He also did not support using such a fund to pay future property tax increases because annual increases should be less than $60,000, something which could be covered by the operating revenue allowance. However, he did recommend that the refund Providence Water receives from Cranston be deposited into an restricted interest bearing account with $375,000 refunded to ratepayers as a reduction to the cost of service for the upcoming three years. The remaining

$385,000 plus interest, under Mr. Catlin's proposal, could be available to Providence Water to pay for the continuing cost of contesting property tax disputes. FN158 This account would be subject to review annually by the Division or in Providence Water's next rate case. Furthermore, all future refunds or rebates from any other taxing authorities would be deposited into the account automatically for review after three years. FN159 As a result of this proposal, Mr. Catlin continued to recommend a reduction to Administrative and General Contract Legal and Engineering Services, updated to reflect the actual test year expense associated with property tax litigation. The adjustment is $100,027. FN160

FN157. *Id*. at 2.

FN158. *Id*. at 2-3.

FN159. *Id*. at 4.

FN160. *Id*.

Addressing the proposed increased operating revenue allowance, Mr. Catlin noted that the Commission recently set Newport Water Department's operating revenue allowance at 1.5 percent of total expenses and indicated a desire to open a generic docket to develop a consistent policy for setting operating revenue allowances for the non-investor owned water utilities in Rhode Island. Therefore, he continued to recommend that the operating revenue allowance for Providence Water be set at 1.5 percent of total operating expenses less miscellaneous revenue. FN161

FN161. *Id*. at 6.

Mr. Mierzwa noted that Providence Water and KCWA accepted his proposed revisions to allocation of T&D mains investment, to updates of several allocation factors initially developed in Docket No. 3163, to recognize costs relative to lost and unaccounted-for water, and to revisions related to the allocation of some source of supply O&M expenses. He also noted that neither Providence Water nor KCWA opposed his proposed modifications to the allocation of miscellaneous revenue. FN162

FN162. Division Ex. 5 (Surrebuttal Testimony of Jerome Mierzwa), pp. 2-3.

Mr. Mierzwa presented a revision to the inch-mile study to include several transmission main sizes that were previously omitted. The revised study indicated that 48.95 percent of Providence Water's mains investment are transmission related. Mr. Mierzwa stated that he reflected the revised study results in his adjustment in order to recognize the costs associated with lost and unaccounted-for water. FN163 Mr. Mierzwa noted that in his rebuttal testimony, Mr. Smith had agreed with the proposal made by Mr. Woodcock relative to the allocation of benefits and pension costs for Customer Service, T&D, Administrative and Insurance functions, but that Mr. Smith had not assigned these costs to the Base category in his rebuttal schedules. Mr. Mierzwa indicated that his prior concerns regarding these allocations were addressed by Mr. Woodcock's methodology. FN164

FN163. *Id*. at 3.

FN164. *Id*. at 3-4.

Addressing additional revenue requirement adjustments made by Mr. Catlin, Mr. Mierzwa stated that he had included them in his cost allocation study. With regard to the property tax refund from the City of Cranston, Mr. Mierzwa indicated that he had allocated that refund consistent with the historical manner upon which it had been allocated to the various cost categories. FN165

FN165. *Id*. at 4.

Turning to the allocation of fire protection demand, Mr. Mierzwa continued to recommend not accepting Providence Water's proposal to reduce the demand costs assigned to fire protection service by 50 percent. He reiterated that

if the Commission is going to adopt a policy of recovering less than the cost of service through fire protection charges, the full cost of providing fire protection service should be identified, and then an explicit decision should be made as to which customers should pay for the unrecovered fire protection service costs. Under [Providence Water']s proposal to reduce demands by 50 percent, the full cost of providing fire protection service is unknown. FN166

FN166.*Id*. at 5-6.

VIII. Hearing

Following public notice, a public hearing was held at the Commission's offices, 89 Jefferson Boulevard, Warwick, Rhode Island, on September 12-13, 2007 for the purposes of hearing evidence and cross examining witnesses in the instant matter. The following appearances were entered:

FOR PROVIDENCE WATER:	Michael McElroy, Esq.
FOR KENT COUNTY WATER:	Joseph McGair, Esq.
FOR THE DIVISION:	William Lueker, Esq. Special Assistant Attorney General
FOR THE COMMISSION:	Cynthia G. Wilson-Frias, Esq. Senior Legal Counsel

Providence Water presented Ms. Marchand, Mr. Gadoury, Ms. Bondarevskis, Mr. Boyce Spinelli, Deputy General Manager of Providence Water, Mr. Bebyn, Mr. Edge, and Mr. Smith. KCWA presented Mr. Woodcock. The Division presented Mr. Catlin.

Addressing the proposed repayment to the City of Providence of past retiree health care costs, Ms. Bondarevskis confirmed that the $248,180 to be paid in each of the following six years, would be entirely for past money owed for the period 1997 through 2005.FN167 She indicated that Providence Water was able to pay the cost for fiscal year 2006.FN168 She conceded that Providence Water is asking the Commission for recovery through future rates of past estimated costs that accrued over a nine year period.FN169 She agreed that the amount being sought by the City was "interest free and it is an estimated amount, but it seemed reasonable." FN170 Ms. Bondarevskis conceded that when Providence Water was filing for previous rate cases, it knew this cost existed.FN171 She agreed that there was no loan documentation between the City and Providence Water for any of those years.FN172

FN167. Tr. 9/12/07, p. 129, 139.

FN168.*Id*. at 139.

FN169.*Id*. at 144.

FN170.*Id*. at 131.

FN171.*Id*. She agreed that she knew retirees are entitled to health care after they retire, but never asked if Providence Water was paying those costs because "it just never occurred to me with all the day-to-day things that come across our desk, day-to-day work that goes on. It never occurred to us."*Id*. at 147-48.She also agreed that the City has always had this cost, but had never asked to be reimbursed. *Id*. at 149.

FN172.*Id*. at 145.

While Ms. Bondarevskis stated that Providence Water verifies the amounts charged by the City to Providence Water for active employees, her testimony seems to indicate that there is no verification for inactive/retired employees.FN173 Furthermore, she stated that the City does not "even track the retirees based on what departments they originally came from."FN174 Ms. Bondarevsksi could not confirm the amount spent on retiree health care costs during the period 1997 through 2005. Furthermore, she clarified that there was no actual data on expenses for 1997 and 1998 for the entire City. FN175

FN173.*Id*. at 132-33.

FN174.*Id*. at 134.She clarified that during discovery, Providence Water did provide a schedule that included only Providence Water employees.*Id*. at 140.Later, Ms. Bondarevskis indicated that the retirement department is separate and it is responsible for its own payroll to retirees. *Id*. at 146-57.Therefore, the City should have some record of the relevant retirees and related healthcare costs.

FN175.*Id*. at 140.

Chairman: “Well, how do you know what the amount is; don't they have a record of what their retirees' healthcare costs were during those years?

Witness: “They would - I believe that was another data request. I'm not sure they have that information. They would have to go back and look up Joe Smow, each individual person and then try to get the records for all of those people, but what they - how they charge us now, the city is self insured.”FN176

FN176.*Id*. at 135-36.

Relying on information received from the City's GASB 43/45 consultant, Ms. Bondarevskis agreed that in 2007, the City began tracking retirees separately from active employees for healthcare expenses and she agreed that before 2004, the costs requested are based on estimates. FN177In fact, prior to 2004, Ms. Bondarevskis agreed that she did not have information from the City regarding how many of the total retirees were former Providence Water employees, but estimated that it would have been approximately in the “80 range”.FN178 Mr. Spinelli indicated that the rates set by the City to recover the cost of healthcare separated active employees from those that are retired and attain the age of 65. At that age, most retirees are then transferred to a medicare supplement plan such as Plan 65.FN179However, Mr. Spinelli could not recall whether, when the actual claim experience was broken out and provided to the City, retirees were in a separate category from active employees or not.FN180He conceded that the funding rates for which the City is seeking reimbursement are still estimates.FN181

FN177.*Id*. at 141-42.

FN178.*Id*. at 142-43.

FN179.*Id*. at 154-55.

FN180.*Id*. at 162.The working rates provided to the City by the health insurance carrier are estimates of future costs. The City is later provided with the actual claim experience.

FN181.*Id*. at 160, 163.

Revisiting issues of Commission concern in the past, Mr. Spinelli agreed that despite the adjustments Providence Water made to its pension contributions in the past, Providence Water had still contributed a percentage of the actuarial recommendation greater than that which was contributed by the School Department and the City of Providence. However, Providence Water was recommending no further adjustments.FN182

FN182.*Id*. at 168-77.

On cross-examination, Mr. Catlin testified that Providence Water had some obligation to ensure they were paying costs incurred in the past, but he could understand how the oversight related to retiree health care occurred. When asked to define retroactive ratemaking, Mr. Catlin stated, “It's seeking recovery for an expense or variation in expense that you could have sought recovery before or you became aware of after the fact and now seeking to recovery it.”FN183He reiterated that if Providence Water had been an investor owned utility, he would have recommended rejecting the request. FN184 However, because Providence Water is regulated on a cash basis, he was recommending approval. He explained that because the Commission presumably would have granted recovery of the expense if requested in the past, it would be reasonable to do so now.FN185 In Mr. Catlin's opinion, the Commission's decision on this issue really is a judgment call based on equities. FN186

FN183.*Id*. at 212.

FN184.*Id*.

FN185.*Id*. at 209-10.

FN186.*Id*. at 227.

Addressing City Service Expense, Mr. Bebyn discussed his methodology for developing the allocators assigned to various departments. He indicated he had met with department heads, reviewed personnel responsibilities to eliminate duplication of efforts and reviewed expenses to determine if any could be removed. He maintained that, contrary to Mr. Woodcock's suggestion, the City Service Expense and Property Tax expense are legitimate expenses of Providence Water and should be included in the calculation to develop the Overhead allocator. He indicated that the Clerk allocator was derived after interviews with personnel and a review of documents. Mr. Bebyn outlined several of his adjustments to various departments and suggested that Mr. Woodcock's proposed adjustments were based on his own opinion rather than an objective critique of City Services.[FN187]

FN187. Tr. 9/13/07, pp. 51-64.

On cross-examination, Mr. Bebyn indicated that he did not review City Council minutes as part of his review of the City Council duties relative to Providence Water.[FN188] He was also unable to provide information where the City Council administration provided the Council with research and/or drafting of ordinances.[FN189] He clarified his testimony relative to the development of the Clerk's office allocator "C", indicating that the allocator was developed by using the number of bids of Providence Water relative to the total of the City plus Providence Water.[FN190] In order to determine whether his allocator was correct for the Clerk's office, he discussed it with them and was told it was reasonable.[FN191]

FN188.*Id*. at 71.

FN189.*Id*. at 79.

FN190.*Id*. at 77.

FN191.*Id*. at 75.

In response to the question that despite the fact that the personnel information related to the mayor's office was not made available to Providence Water, was Mr. Bebyn "confident that all these people spend 8.14 percent of their time on Providence Water related activities," Mr. Bebyn responded, "It was a function of not just time, it was a function of oversight."When asked if that included somebody in the Mayor's office who "goes out to get coffee for the Mayor or goes and gets lunch, his driver, those kinds of things," Mr. Bebyn answered, "I don't have that detail, no." However, the department was assigned the general overhead allocator.[FN192] Other instances of questioning regarding specific functions of departments were met with similar responses.[FN193]

FN192.*Id*. at 84.

FN193.*See id*. at 70, 85-86.

Mr. Bebyn confirmed that the calculation of the fringe benefit factor of 72 percent applied to salaries was correct while Providence Water's fringe benefits are calculated at 60 percent, or 12 percent lower. Mr. Bebyn was unable to explain the difference.[FN194]

FN194.*Id*. at 88-89.

On cross-examination, Mr. Woodcock testified that he had done no independent studies of the city departments to determine their functions relative to the support of Providence Water, but had instead based his adjustments off of Mr. Bebyn's analysis.[FN195] Mr. Woodcock opined, when questioned by the Commission and Providence Water's attorney, that the existence or nonexistence of a water board would be a relevant factor to review when considering the level of services necessary for a host city to support its water utility.[FN196]

FN195.*Id*. at 111.

FN196.*Id*. at 134, 144.

On cross-examination, Mr. Catlin testified that with regard to City Services, he "looked at the overall level of the costs and looked at the overall allocation," stating that in most cases one cannot "directly identify which services are provided to which agencies by any particular city office."Therefore, he testified, "I made an evaluation that the overall allocation factor that Mr. Bebyn...used was appropriate."He stated that he chose not to "look at each individual department that couldn't be allocated because I'm sure you could find, as Mr. Woodcock did in his opinion, departments where not as much service....” was provided and other departments where more service was provided than that which was allocated.FN197

FN197. Tr. 9/12/07, p. 203.

Addressing the proposed reduction in demand allocated to fire protection, Mr. Smith explained that Providence Water started with the assumed demand that was accepted in the prior general rate filing and reduced that max day and max hour demand by 50 percent. He reiterated that the primary reason was “to reduce the amount of money that the Water Supply Board was recovering through public fire protection” because of inequities relating to the fact that tax exempt institutions were not paying for fire protection through property taxes.FN198 He conceded that this was a policy determination by Providence Water as opposed to rectifying an incorrectly developed cost of service in the past.FN199 Mr. Smith also conceded that, assuming the Commission's policy has been to bring public and private fire protection rates in line with their respective costs of service, this proposal would not coincide with that policy. FN200

FN198. Tr. 9/13/07, p. 195.

FN199. *Id*. at 195-96.

FN200. *Id*. at 196.

IX. Post-Hearing Briefs

On October 12, 2007, the parties submitted post-hearing briefs responding to the Commission's request to address whether or not the request for funding through rates to reimburse the City of Providence for prior years' retiree health care benefits would constitute retroactive ratemaking. Each of the parties opined that, based on R.I.Gen.Laws § 39-3-11.1 and related Supreme Court interpretations of the statute, the request is either not retroactive ratemaking or exempt from the prohibition on retroactive ratemaking.FN201 Providence Water also argued that because the City had not requested payment for the retiree health care costs for the period 1997-2005 until 2006, it was not a past obligation, but rather a current one. Furthermore, Providence Water argued that this expense was unexpected.FN202

FN201. Providence Water Brief, pp. 10-12; KCWA Brief, pp. 1-2; Division Brief, pp. 1-8. R.I. Gen. Laws § 39-1-11.1(a) states: Notwithstanding any other provisions of this chapter, the commission shall not have the power to suspend the taking effect of any change or changes in the rates, tolls, and charges filed and published in compliance with the requirements of §§ 39-3-10 and 39-3-11 by any public waterworks or water service owned or furnished by a city, town, or any other municipal corporation defined as a public utility in § 39-1-2, when the change or changes are proposed to be made solely for the purpose of making payments or compensation to any city or town for reimbursement of any loans or advances of money previously issued to any public waterworks or water service by any city or town under existing contracts or arrangements; provided, however, that the change or changes shall take effect subject to refund or credit pending further investigation, hearing, and order by the commission within eight (8) months after the effective date. The public waterworks or water service shall file with the commission the new rate schedule along with the documentary evidence of the indebtedness supporting the new rates. Further, the rate schedule shall be published in a newspaper of general circulation in the service area by the waterworks or water service at least ten (10) days prior to the effective date thereof.

FN202. Providence Water Brief, pp. 11-12.

In addition to discussing issues upon which the parties agreed, Providence Water indicated it was prepared to send out conservation notices in compliance with R.I. Gen. Laws § 39-3-37.1 as long as they are funded. FN203 Providence Water argued in favor of its proposed three percent operating reserve with a portion restricted and a portion unrestricted.FN204 Providence Water also argued that KCWA's proposed adjustments to City Service expense were unsupported by the record and that its proposal to change the methodology for calculating lost and unaccounted for water should not be entertained by the Commission.FN205 Additionally, Providence Water argued that the proposed 25 percent fixed wholesale charge is reasonable and would provide revenue stability.FN206 Another argument made was that more public fire protection should be included in consumption charges rather than in the fire protection charge "in order to have tax exempt properties pay their fair share."FN207 Finally, Providence Water argued that the Commission should reconsider its prior decision regarding the allocation of employee pension and benefit costs.FN208

FN203.*Id*. at 3

FN204.*Id*. at 5-8.

FN205.*Id*. at 12-15, 17-18.

FN206.*Id*. at 15.

FN207.*Id*. at 16.

FN208.*Id*. at 16-17.

In its Brief, KCWA reiterated its arguments regarding adjustments to City Service expense, pumping expense, the fixed wholesale charge, and cost allocations. The Division agreed with Providence Water that the Commission should not consider KCWA's position to change the methodology for calculating lost and unaccounted-for water. The Division also agreed with Providence Water that the Commission should revisit its prior decision regarding the allocation of employee pensions and benefits. The Division reiterated its arguments regarding the operating revenue allowance, and Cranston tax refund, noting that Providence Water had agreed to the Division's proposal regarding treatment of the refund.FN209 Discussing the proposed fire protection charges, the Division noted that Providence Water's proposal also reduces the demand allocated to private fire protection service, requiring all water customers to bear a portion of private fire protection costs as part of their consumption charge, that IFR costs are already required to be included only in consumption charges and as a result, fire protection charges are already subsidized, and that the proposal provides less revenue stability to Providence Water when their goal is for revenue stability.FN210

FN209.*Id*. at 8-14.

FN210.*Id*. at 15.

X. Commission Findings

On October 30, 2007, the Commission conducted an open meeting for the purposes of considering Providence Water's rate application. The Commission notes that few issues regarding cost of service remained between the parties. The Commission ruled on the following cost of service issues: Pro forma consumption, conservation notice, restricted accounts, reporting requirements, number of funded positions, treatment of salary increases, treatment of the Cranston property tax refund, net operating reserve, repayment to City of past retiree health care expense, and City Service expense. Additionally, there were issues remaining regarding cost allocations and rate design: proposed wholesale fixed charge, proposed demand reduction to fire service, methodology for measuring lost and unaccounted-for water, reallocation of pensions and benefits in Customer Accounts, labor allocation relating to pumping costs, allocation of Western Cranston Fund, and Allocation of Miscellaneous Revenues.

As a result of the Commission's decision, Providence Water Supply Board is granted a revenue increase of $6,935,500 versus the $9,688,321 originally proposed, for a total cost of service of $58,086,064 to be applied to usage on and after November 1, 2007.FN211

FN211. See Appendix A and Appendix B, attached (Providence Water Supply Board, Docket 3832 Cost of Service and Cost of Service Adjustments).

A. Pro Forma Consumption, Number of Services, Meters & Connections, Conservation Notice

The parties agree that the rate year consumption calculation should be based on an average of years that includes the most recent data available, namely FY 2007 consumption. The Commission also agrees and will use the average consumption from the 2004 through FY 2007 period. The Commission also directs Providence Water to utilize the updated customer counts for services, meters and hydrants. This will provide the most accurate calculation of rates.

During the hearing, it became clear that Providence Water has not been sending out conservation notices required by R.I. Gen. Laws § 39-3-37.1. Providence Water recognizes and agrees to the requirement. Estimates provided by its printer vendor indicate that a simple bill insert setting forth the information listed in the statute would cost approximately $2,016.[FN212] The Commission directs Providence Water to send out such a conservation notice annually and allows $2,100 in rates to cover the cost.

FN212. Providence Water Response to Commission Record Request 3 (dated September 21, 2007).

B. Reimbursement to the City of Past Retiree Health Care

Providence Water is seeking recovery through future rates of $1,489,080 over six years to pay the City of Providence for Providence Water's portion of retiree health care that has supposedly been paid by the City on the utility's behalf for over nine years. According to Providence Water, the City never billed Providence Water for the retiree health care when the costs were incurred. Providence Water is now requesting reimbursement on behalf of the City for the period 1997 through 2005.[FN213] Providence Water's main argument is that this is a cost the utility should have been paying all along and they were not. Therefore, it would only be fair to repay the City out of future rates, for the estimated costs the City incurred in the past. For the reasons set forth herein, the Commission rejects Providence Water's request. The resulting adjustment is a reduction to Providence Water's request in the amount of $248,180.

FN213. Providence Water was billed for and paid the 2006 retiree health care from existing rates.

The prohibition against retroactive ratemaking is a fundamental principle of utility regulation. As the Supreme Court has stated, "One of the central principles of ratemaking is that rates must be prospective. It is well settled that rates are exclusively prospective in nature and that future rates may not be designed to recoup past losses."[FN214] Furthermore, the rule against retroactive ratemaking "protects the public by ensuring that present consumers will not be required to pay for past deficits of the company in their future payments."[FN215] The prohibition against retroactive ratemaking is important because, to summarize the Indiana commission, it serves to protect customers by ensuring current users pay for service they receive as opposed to costs associated with past service and to require utilities to bear losses and enjoy benefits based on their efficiency of management.[FN216]

FN214.*Providence Gas Co. v. Burke,* 475 A.2d 193, 197 (R.I. 1984).

FN215.*Narragansett Electric Company v. Burke,* 415 A.2d 177, 179 (R.I. 1980).

FN216. 1 LEONARD SAUL GOODMAN, THE PROCESS OF RULEMAKING 165-166 (Public Utilities Reports, Inc., 1998) (citations omitted). The third purpose behind the rule against retroactive ratemaking is to prevent "utilities from using future rates to protect the financial investment of their stockholders..."*Id. See* Division's Brief, p. 2.

At the hearing, the Division's witness defined "retroactive ratemaking" as "seeking recovery for an expense that you could have sought recovery before or you became aware of after the fact and now seeking to recover it."[FN217] In this case, Providence Water is requesting that over the next six years, ratepayers be required to pay for nine years' worth of past retiree health care costs for which the utility was responsible but for which it did not pay. This is clearly an example of retroactive ratemaking.FN218

FN217. Tr. 9/12/07, p. 212. The Division's witness claimed that if this had been an investor owned utility, he would recommend denial based on retroactive ratemaking.

FN218.*See* Tr. 9/12/07, p. 212.

Providence Water claims that because the City did not bill it for the expense for over nine years, it is a current, not past expense. Therefore, Providence Water maintains, there would be no retroactive ratemaking. The Commission does not accept this rationale because the expense existed for the past ten years and could have been recognized by any number of officials at Providence Water or in the City of Providence within a reasonable time period.

Furthermore, payment for the health care is due each year and therefore, each year's expense was due in the year during which it was incurred. Had the City appropriately charged Providence Water for the annual expenses, Providence Water would have had the opportunity to pay its bills. In fact, in 2006, when Providence Water was charged for the retiree health care expense for that year, it was paid out of operating revenues. Therefore, the rationale cited by Providence Water and KCWA, arguing that the Supreme Court has already found this type of situation not to be retroactive ratemaking, is not persuasive.FN219 Under these circumstances, it is clear that Providence Water is seeking future recovery of past costs, which falls squarely under the definition of retroactive ratemaking.

FN219. KCWA cites the Supreme Court's decision in *Kent County Water Authority v. State Dept. of Health,* 723 A.2d 1132 (R.I. 1999) as a basis for determining that this situation does not constitute retroactive ratemaking. In that case, KCWA argued that because it did not have funds in its rates to pay an annual DOH licensing fee, billing it for past due accounts would require it to make a rate filing to the PUC seeking a retroactive rate case. The Supreme Court disagreed with this contention, finding that “DOH always billed petitioner for the annual approval fee in advance of each fiscal year for which petitioner was obliged to obtain DOH's approval to operate its public water-supply system. The mere fact that DOH has continued to demand payment from petitioner of these past-due, multi-year arrearages...does not constitute a coercion of petitioner into retroactive ratemaking.”*Id.* at 1137.The Supreme Court noted that there were many ways KCWA could have paid the annual fee out of its then current rates or it could have initiated a rate case in order to avoid the arguable retroactive ratemaking situation. *Id.* at 1137.Providence Water was not billed on an annual basis by the City, appears to have been in the position where they should have been aware of the retiree health care obligation, and had multiple rate cases before the Commission during the time in question when it was apparently supposed to be paying these expenses. Providence Water's cost is not a current charge by the City like DOH's. DOH acted responsibly in assessing the fee on an annual prospective basis. The City did not. Therefore, Providence Water's argument that this is not a retroactive obligation, but a current obligation owed by Providence Water to the City is unsupported by the evidence where all parties agree that this was an expense Providence Water should have been paying all along. Relying on the City's delay in billing does not make this a current expense. It is still a prior obligation.

Like all rules, the Supreme Court has recognized limited exceptions to the rule against retroactive ratemaking, noting that “no rule shall be blindly applied, however, without prior consideration of the underlying policy that the application of the rule in a particular instance will not undermine its original purpose.”FN220 First, there is an emergency exception, where there is an extraordinary expense caused by an event that is unpredictable and not within the control of the utility. In such circumstances, the Court found that the public interest in having the utility expend extra costs in order to quickly restore power after an extreme storm outweighed the rationale behind the prohibition on retroactive ratemaking.[FN221] Second, there is an exception for reviews of past costs in conjunction with a reconciliation tariff. For instance, noting that "the specter of retroactive ratemaking must not be viewed as a talismanic inhibition against the application of principles based upon equity and common sense," the Court found that a review of past costs associated with a reconciliation tariff was not retroactive ratemaking, but a necessary function of the Commission under that type of tariff.[FN222] Third, the Court has recognized the statutory exception of R.I. Gen. Laws § 39-3-11.1(a) which applies to a municipally owned water utility when it is repaying a loan or advance to its host city or town. The statute allows an immediate rate increase followed by a Commission review.[FN223] As will be discussed further, the Commission finds that none of these exceptions applies to Providence Water's instant request.

FN220. *Narragansett Electric Company v. Burke*, 415 A.2d at 178.

FN221. *Id*. at 179, *stating* ("the rule [prohibiting retroactive ratemaking] serves to protect present customers from paying for a utility's past operating deficits. This aspect of the rule must be weighed against the interest of providing immediate service to customers when a destructive, unexpected storm occurs. On such an occasion the public interest in quickly restoring heat and electricity to the homes of customers must prevail....The next time a storm of this magnitude occurs, the company would have no incentive to hire outside line and tree crews to restore service efficiently and swiftly to customers if no reimbursement for extraordinary expenses would be forthcoming. Thus, application of the rule to expenses related to such an emergency situation so inextricably related to the public health and safety would serve to thwart the goal of effective customer service.") *Id*. at 179-80.

FN222. *Roberts v. Narragansett Electric Co.*, 470 A.2d 215, 217 (R.I. 1984). *See Blackstone Valley Electric Co. v. PUC*, 42 A.2d 242 (R.I. 1988) (noting that this case involved a reconciliation tariff requiring the Commission to review past costs). Such a situation does not exist in this case. These are general operating expenses, not expenses designed to be passed through on a regularly-occurring reconciliation basis.

FN223. *See* Providence Water v. Malachowski, 624 A.2d 305, 310 (R.I. 1993) *finding*, "The PWSB claims that the rate-making statute limits the commission's inquiry to the existence and legitimacy of loans and advances. We disagree with this interpretation of the statute. Section 39-3-11.1 leaves the commission with substantive review of the PWSB's rate filing....We now reiterate that § 39-3-11.1 does not abrogate the review provisions of the regulatory scheme in chapter 3 of title 39. It merely defers them."(citations omitted).

Regarding the statutory exception, R.I. Gen. Laws § 39-3-11.1(a) states in part, that a municipal water utility can change its rates without being subject to suspension by the Commission where "the change or changes are proposed to be made solely for the purpose of making payments or compensation to any city or town *for reimbursement of any loans or advances of money* previously issued to any public waterworks or water service by any city or town under existing contracts orarrangements."[FN224] Thus, to determine whether the statutory exception applies, the Commission's first inquiry is into "the existence and legitimacy of loans and advances." made by a host city or town to the utility.[FN225] Based on the following reasoning, the Commission finds that there was no existence of a loan or advance.

FN224. R.I. Gen. Laws § 39-3-11.1(a) (emphasis added).

FN225. *See* Providence Water v. Malachowski, 624 A.2d 305, 310 (R.I. 1993).

According to Black's Law Dictionary, a loan is a sum of money provided for the payment of something with the expectation of repayment.FN226 In every case cited by the parties, it was clear that there was a loan or advance. FN227 Providence Water admits no loan documentation exists in this case and neither the Annual Reports for the City nor the Providence Water Supply Board appear to contain reference to any amount owed by Providence Water to the City of Providence for past retiree health care expense in the reports reviewed by the Commission.FN228 In fact, Providence Water never claimed that this expense constituted repayment of a loan or advance.

FN226. BLACK'S LAW DICTIONARY 936 (6th ed. 1990).

FN227. *See In re: Woonsocket Water Dept.*, 538 A.2d 1011, 1015 (R.I. 1988); *See Providence Water Supply Board v. Malachowski*, 624 A.2d 305, 306 (R.I. 1993).

FN228. Tr. 9/12/07, p. 145. Commission Exhibit 1 (Providence Water Response to Commission Data Requests 3-1, 3-8). Providence Water's Annual Reports are on file with the Commission. The Division's brief also notes that there is no loan documentation, not even an informal note between the City and utility.

According to Black's Law Dictionary and Webster's Dictionary, an advance is to pay (money or interest) before legally due.FN229 This was not a situation where the City was paying Providence Water's obligation before it came due and ten years later, it is now due from Providence Water. Retiree health care expense is an annual expense and should have been paid as incurred.

FN229. BLACK'S LAW DICTIONARY 52 (6th ed. 1990); Webster's II New College Dictionary, 16 (Houghton Mifflin 1999).

Because the Commission finds that there was no loan made during the years 1997 through 2005 and no advance of money, the statute does not appear to apply to Providence Water's request. In order for the statute to apply, a loan or advance would have to now be defined as any money, whether known or unknown, paid by a City, not charged to the utility, and where repayment is demanded up to 10 years later. This would be an unreasonable interpretation which the Commission will not adopt.

The intent of this statute is not to create a blanket exception for municipal water utilities from the rule against retroactive ratemaking.FN230 When the Supreme Court speaks to the reason the statute allows for retroactive recovery of expenses by municipal water utilities, it speaks in terms of revenue deficiencies that have to be covered by taxpayers.FN231 In finding that the surcharge allowed under R.I. Gen. Laws § 39-3-11.1 applied despite the fact that it collects past expenses from future ratepayers, the Supreme Court has stated, "[t]hose revenues that the water utility *cannot* recover from the users, the city provides through taxes, not voluntary investors."FN232 There was no claim by Providence Water that it could not pay its retiree health care because of revenue deficiencies during the years such expenses should have been paid. In fact, in 2006, Providence Water met its obligation without a request for rate relief. Therefore, the Commission does not believe the intent behind R.I. Gen. Laws § 39-3-11.1 applies to Providence Water's request.

FN230. Providence Water quotes, "a publicly owned water authority is exempted from the ban on retroactive rate making normally applied to privately owned public utilities." *See O'Neil v. Malachsowski*, 604 A.2d 1268 (R.I. 1992). In fact, this holding only applies if R.I. Gen Laws § 39-3-11.1 is applicable, which it is not under the current circumstances. Furthermore, in the subsequent case reviewing the same issue, the Court upheld the Commission's decision to disallow a portion of the loan Providence Water could repay the City. *See Providence Water Supply Board v. Malachowski*, 624 A.2d 305 (R.I. 1993). That *Providence Water* decision specifically stated that the Commission's review under the statute "exceeds mere regulation. Section 39-1-1 vests the commission with the power to regulate and to *supervise* the conduct of the PWSB for the purpose of controlling its efficiency and protecting the public against improper and unreasonable rates."*Id*. at 309 (emphasis in original). Furthermore, "without the commission's guidance, the PWSB will have little incentive either to adopt proper fiscal management or to adhere to statutory requirements."*Id*. at 311.A blanket exception from the prohibition on retroactive ratemaking for municipal water utilities would make it very difficult for the Commission to fulfill this statutory mandate and discourage efficiency while encouraging inefficiency and allowing Providence Water to be used by the City to rectify its own prior mismanagement, thus thwarting the Court's finding that proper supervision and the exercise of fiscal prudence by the Commission will also protect taxpayers. *See id*.

FN231.*In re: Woonsocket Water Dept*., 538 A.2d 1011, 1014-15 (R.I. 1988).

FN232.*In re: Woonsocket Water Dept*., 538 A.2d at 1014-15 (emphasis added).

The next question is whether there is a non-statutory exception to the prohibition against retroactive ratemaking that would apply to Providence Water's situation. Utilizing broad policy statements made by the Supreme Court when reviewing matters related to retroactive ratemaking, either under the statute or not, Providence Water maintains there is. The Commission does not agree.

Regarding the exception to the prohibition against retroactive ratemaking where there was an event, unforeseeable by the utility and not within the utility's control, the Court found an exception where an electric utility was seeking recovery of expenses it had incurred to restore service "after the crippling ice storm of January 14, 1978...described as the most destructive in the company's experience." FN233 The Court has also recognized the exception where a utility was faced with an unexpected supplemental tax increase. The Court found that "the company, in establishing its rates for 1981, necessarily had to predict the tax rate for 1980. However, it would have been impossible for them to have predicted the *supplemental* tax surcharge assessed by the city. This expense itself was extraordinary....It is clear that the company is faced with a one-time surcharge and is seeking recovery not for an improperly anticipated property tax increase but for a retroactive charge that would be impossible to foresee."FN234

FN233.*Narragansett Electric Company v. Burke*, 415 A.2d 177 (R.I. 1980).*See supra* notes 178-79 and accompanying text.

FN234.*Providence Gas Co. v. Burke*, 475 A.2d 193, 198 (R.I. 1984). Finally, the Court has recognized an exception where a federal or state reconciliation tariff applied to a past charge. That situation does not exist here.

Likewise, in *Blackstone Valley Electric Co. v. PUC*, the Court found that Blackstone Valley Electric (BVE) was entitled to collect from ratepayers past additional expense charged by its wholesale supplier for coal even though the supplier did not recognize that there would be an additional expense for almost one year and did not charge the utility for 18 months.FN235 In holding that the Commission erred in denying the pass-through cost as retroactive ratemaking, the Court held that this case fit under the emergency exception as an unexpected event, noting that "the fuel adjustment clause will apply to reflect fluctuations in the cost of fuel charged by the Company's wholesale suppliers of power." FN236 According to the Court, "Blackstone *could not* have foreseen a decrease in the energy value of Montaup's coal pile in Somerset. For almost one year even the managers at Montaup were unaware of the moisture content problem. In short, the situation that led to the surcharge was an extraordinary event that is unlikely to occur." FN237

FN235.*Blackstone Valley Electric Co. v. PUC*, 542 A.2d 242, 243-44 (R.I. 1988).

FN236.*Blackstone Valley Electric Co*, 542 A.2d at 244.

FN237.*Id*. at 245 (emphasis added).

The Commission finds that just because neither the City nor Providence Water recognized the expense for over nine years that does not mean they could not have. BVE had no control over the storage of the coal or the testing. Providence Water had control over its own books and knew they were paying for current employees' healthcare. Providence Water knew that retirees were entitled to health care, but “it never occurred to [them]” to inquire.FN238 Therefore, this was not an unforeseen event over which Providence Water had no control, and thus, the facts of the BVE case are inapplicable to the circumstances surrounding Providence Water's request.

FN238. Tr. 9/12/07, p. 149.

In addition, Providence Water's failure to pay retiree health care from 1997 through 2005 was not unforeseeable, extraordinary or beyond the control of the utility. This is not a situation where the expense was unforeseeable. In fact, Ms. Bondarevskis, Providence Water's Director of Finance, testified that she was aware Providence Water retirees were receiving health care coverage. FN239 This was also not a situation outside of the control of the utility. Anyone at Providence Water or the City could have raised the issue, and the expense could have been paid as incurred. Finally, the expense was not extraordinary. These were regular annual operating expenses that, but for the poor management of the City, were not charged to Providence Water. Additionally, at any time, Providence Water could have questioned why it was not paying these charges.

FN239. Tr. 9/12/07, p. 147.

Regarding the exception for reconciliation tariffs, in *Providence Gas Co. v. Burke*, the Court found an exception to the prohibition against retroactive ratemaking where a federal or state reconciliation tariff applied to a past charge. In another case, the Court held that the “commission also erred by not allowing a fuel adjustment assessment pass through in accordance with the provisions of Blackstone's tariff.” FN240That situation does not exist here. Providence Water is not seeking recovery for charges that are permitted through a federal or state reconciliation tariff.

FN240.*Blackstone Valley Electric Co*. 542 A.2d at 245.

Even if the Commission found that the prohibition against retroactive ratemaking should not apply, it is unclear what amount for retiree health care should be allowed. In order to calculate the amount to be paid back, according to Ms. Bondarevskis, the City Controller's office started with actual costs for fiscal years 2005 and 2004, discounted the costs back for each fiscal year 2003 through 1997, based on the annual working rate increase. In Ms. Bondarevskis' opinion, this was “a reasonable method of *estimating* the outstanding liability.” FN241The claimed expense is an *estimate*. Ms. Bondarevskis used this term in her pre-filed testimony and two Providence Water witnesses testified at the hearing that, no matter how close the estimates may be to actuals, they are still estimates.FN242The Commission can set rates based on estimates. However, those are *prospective* costs, not *past* expenses. Past expenses must be accurate and verifiable. Providence Water was presented with the opportunity to provide the Commission with actual retiree health care expenses. The utility objected to the question on that basis that it was overly broad and unduly burdensome. At the hearing, Ms. Bondarevskis testified that it could be done.FN243Under R.I. Gen. Laws § 39-3-12, the burden of proof is on the utility to present and prove its expense, but Providence Water objected and refused to provide the information.FN244Therefore, Providence Water failed to prove its case.

FN241. Providence Water Ex. 3, p. 7-8 (emphasis added).

FN242. Tr. 9/12/07, pp. 131, 139, 142, 144, 160, 163.

FN243.*See* Tr. 9/12/07, pp. 136, 141. In fact, Providence Water refused to answer a related data request, not based on impossibility, but on the claim that the request was overly broad and unduly burdensome. Commission Exhibit 1 (Providence Water Response to Commission

Data Request 7).

FN244. Commission Exhibit 1 (Providence Water Response to Commission Data Request 7). Because the City never distinguished prior to 2006 between active and retired (but younger than 65 years old) employees until for purposes of setting premiums, it is unclear whether some of the retiree costs were already included in active employee premiums. This would affect the amount owed.

Finally, with regard to the "it's only fair to pay what we should have been paying" argument, which the Commission notes is what retroactive ratemaking is, the Commission also points out that over several years, Providence Water contributed a percentage of its actuarially recommended contribution to the City's pension system higher than what the City and School Department contributed. Although Providence Water reduced its contributions in order to balance the contributions for a short period subsequent to 2002, the ratepayers still have subsidized taxpayers in the past in the range of $494,859-$979,002, depending on how many years are reviewed.[FN245] The Commission notes that neither the City of Providence nor Providence Water is proposing to have the City's taxpayers reimburse Providence Water's ratepayers for such subsidization.

FN245. *Order No. 18496* (issued January 11, 2006). Commission Exhibit 4. For the time period 1997 through 2002, the comparable time period for which repayment to the City is being requested, Providence Water's payment in excess of the contribution by the City and School Department was $494,859 and looking back at the time period 1992 through 2002, a comparable number of years, it was $979,002. Providence Water's response to Commission Record Request 6 (dated October 3, 2007).

For all of these reasons, the Commission reiterates its determination that the request to repay past retiree health care is denied.

C. City Services Expense

In Docket No. 3163 (Rate Year 2001), the Commission approved a Settlement wherein $806,769 was allowed for Providence Water's City Service Expense. As part of the Settlement, Providence Water agreed to reevaluate and study these expenses in its next rate filing. In Docket No. 3446 (Rate Year 2003), the Commission approved a Settlement wherein City Services was reduced to $729,994. In Docket No. 3684 (Rate Year 2006), Providence Water did not request an adjustment to City Service Expense. In this rate filing, Providence Water is requesting an increase of $515,958 for a total City Service Expense of $1,245,952.

The Commission has the legal authority to modify City Service Expense just like any other expense if it either finds the expense not to be just and reasonable or if it is unsupported by the facts presented to the Commission. City Services has been a cause of concern for the Commission since at least 1988.[FN246] In the instant docket, Providence Water has provided the Commission with a study which reviews the functions of various departments of the City and assigns an allocator to each departmental budget (after removing some personnel in some instances). Each department then has a dollar amount assigned to it.[FN247] Providence Water's witness indicated that he met with department heads to discuss the functions and after assigning the allocators, asked them if they believed the amounts were reasonable.[FN248] At the hearing, Providence Water's witness was subject to extensive cross examination during which he was unable to explain what various positions within departments did to provide support to Providence Water despite the fact that all positions were included as providing support to the Providence Water Supply Board.

FN246. In Docket No. 1900, the Commission allowed contested City Service Expenses relying on Providence Water's assertion that "City Services expenses are 'based on actual costs incurred by the Board as verified by its auditors."' *Order No. 12796* (issued November 14, 1988). *See* *Audobon Society of Rhode Island v. Malachowski*, 569 A.2d 1 (R.I. 1990) (affirming Commission's adjustments to City

Service Expense) In the instant docket, Providence Water provided the Commission with a study, but does not allege the associated costs are based on actual costs incurred by the Board from the departments.

FN247. The Commission notes that this is similar to the methodology used in Docket No. 3163.

FN248.*See* Tr. 9/13/07, p. 75.

KCWA's witness argued several issues and made adjustments to allocators based on his double counting argument as well as adjustments to specific departments. FN249 However, at the hearing, KCWA's witness conceded that he had done no independent review of the departments, but rather, had made specific adjustments based on his own judgment. The Division made the decision to "look at the overall level of the costs and look at the overall allocation," but not at specific allocations in the way KCWA's witness did, noting that some departments may be over-allocated and some under-allocated.FN250

FN249. The Commission also believes that while Mr. Woodcock's testimony that property taxes require no support by the City, the Commission does agree with the concept that the level of property taxes does not correlate to the level of support provided by the City to issue checks.

FN250. Tr. 9/12/07, p. 203.

The Commission is concerned that departmental costs included a fringe benefits amount of 72 percent of wages which is 12 percent higher than the fringe benefits assigned to Providence Water. While the Commission believes this is an accurate calculation of the City personnel's fringe benefits, the Commission is concerned that ratepayers are being asked to subsidize such a high level of benefits. Troubling also to the Commission is that the Division requested information regarding personnel in the mayor's office. However, despite the fact that this is information required to be disclosed under an Access to Public Records Act request, Providence Water stated it was unavailable. FN251

FN251. Information related to specific personnel costs of the mayor's office was withheld from the parties, and therefore, from Commission review. Based on information the Commission was able to gather, the mayor's salary and benefits total $215,000. The average salary and benefits for the remaining employees total $101,762. Therefore, the total of $264,287 allocated from the mayor's office includes the equivalent of 2 full time equivalents (3640 hours per year) plus more than 8.08% of the mayor's salary. (*See* Commission Exhibit 1). The General Overhead allocator is 8.08 percent of total departmental costs. It is difficult to envision this level of service being provided to Providence Water in light of the fact that this would be significantly more than the oversight described by Mr. Bebyn in his testimony. Additionally, the Commission is skeptical of the level of support provided in light of the fact that Mr. Bebyn conceded that he did not have information to discount positions such as the mayor's driver, a position that might, at best, tangentially benefit ratepayers.

Because the Commission does not find Mr. Bebyn's study to be sufficient evidence upon which to review the reasonableness of the City Service expense requested to be funded through rates and Mr. Woodcock's alternatives appeared to be based more on subjective evaluation rather than objective criteria, the Commission was unable to determine the known and measurable City Service expense from the evidence presented. Under R.I. Gen. Laws § 39-3-12, Providence Water has the burden of proof which it failed to meet on this issue. Therefore, the Commission determines that the best approach is to take the last amount approved as just and reasonable for calendar year 2006 and to adjust it upward by the inflation percentage utilized for certain other expenses in this filing to reach an appropriate expense for Calendar Year 2008.

Therefore, because the Commission does not have sufficient evidence upon which to make a determination as to the just and reasonableness of the parties' respective positions, but recognizes that there are services provided to Providence Water by the City, the Commission is taking the last approved City Service Expense of $729,994 and increasing it by the 2.5 percent per year inflationary level that has been agreed to in this rate filing in order to adjust from Rate Year 2006 to Rate Year 2008. The total City Service Expense is $776,568 plus Stop Loss Insurance and GASB 43/45 Consulting totaling $62,559 for a total of $839,167.[FN252] The adjustment is a $401,188 reduction to Providence Water's request. All regulated municipal water utilities are now on notice that in the future, the Commission will approve only verifiable departmental expenses charged by the City Departments to the respective water boards, departments or divisions for services rendered.

FN252. The Stop Loss Insurance is a verifiable number and is based on the number of Providence Water employees divided by the number of (Providence Water + City of Providence) employees as the insurance relates to each employee. Therefore, this is a reasonable calculation that was not previously included in City Services. In addition, the GASB 43/45 Consulting allocation is a new charge due to the change in regulations. The Commission finds the calculation and allocation of this verifiable charge to also be reasonable.

D. Restricted Accounts, Positions and Salaries, Cranston Property Tax Refund, Operating Revenue Allowance, Reporting Requirements

The Providence Water Supply Board shall continue to restrict the following accounts in the following amounts collected through rates: Capital Improvements - $2,450,000; Western Cranston Fund - $62,069; IFR - $13,900,000; Meter Replacement - $1,000,000; Insurance Fund - $2,967,655; Chemicals and Sludge - $3,132,565; and Equipment Replacement - $600,000. As in the past, unspent funds within the restricted accounts at the end of each year shall remain in the respective accounts, subject to any modifications stated herein. Providence Water shall report the activity within its restricted accounts three times per year, or once every four months.

Providence Water shall file timely reports with the Commission. Semi-annual Reports shall be filed with the Commission no later than 90 days from the end of the reporting period. Failure to file all required reports prior to filing another rate case shall result in rejection of such rate case under the Commission's Rules of Practice and Procedure. In addition to the current requirements of the semi-annual reports, Providence Water shall also include the following with its semi-annual reports: (1) Pensions: amount of contribution, percentage of actuarial recommendation compared to the City's and the School Department's, any changes to the pension plan, the cost of the pension contribution as a percentage of actual payroll of those who are in the pension system, and once per year, shall provide the annual report from Providence Water' actuary on the pension plan and the annual audited report on the pension plan;[FN253] (2) Retiree Health Care Reporting related to GASB 43/45 actuarial recommendations: amount of contribution, percentage of the actuary's recommendation compared to the City's and the School Department's. Any amounts allowed in rates in excess of the actual contribution shall be restricted.

FN253. Providence Water agreed to the additional reporting. Tr. 9/12/07, pp. 123-24.

In addition, Providence Water shall create a separate restricted account entitled Property Tax Refund into which the funds received from the City of Cranston ($1,510,096.16) shall be deposited. Out of that account, $375,000 shall be credited to customers annually, for a total over three years of $1,125,000.[FN254] The remaining balance in the account shall be used for litigation expenses related to property tax challenges, but not increased property taxes. Funds may be expended only on invoices for services rendered on and after November 1, 2007. In addition, any future tax refunds or adjustments in Providence Water's favor shall be deposited into this account for further disposition as ordered by the Commission. In conjunction with its semi-annual financial report, Providence Water shall provide to the Commission, with a copy to the parties to this docket, a reconciliation of the activity in the account. Finally, there was no objection to KCWA's proposal that if after three years, there is any money remaining in the account, it is to be held for disbursement back to ratepayers in proportion to the current tax allocation or reconsideration by the Commission with notification to all parties in this docket. However, because the Commission does not know how long the currently pending tax challenges will take, the Commission will review the balance of the account and entertain proposals by Providence Water regarding the appropriate future treatment of the funds within the account. Because the Commission has accepted the proposal of the parties with regard to the appropriate treatment of the City of Cranston tax refund, the Commission is reducing the Administrative and General Contract Services by the increase requested, or $100,027.

FN254. In reality, the $375,000 per year has been calculated into the rates approved by the Commission in this docket and will not constitute an additional rate credit to customers. The Commission presumes that Providence Water will credit the amount to its operating revenues on a schedule that will allow it to withdraw no more than the $375,000 annually.

The number of positions funded in this rate case is 263, including full-time and part-time. Providence Water indicated that this is the average over the most recent 14 month period.[FN255] Providence Water shall also restrict the equivalent of a 3 percent increase in salaries and benefits ($947,203) for the purpose of covering anticipated salary and benefits increases when a new labor contract is entered into between the City of Providence and Public Employees' Local Union 1033.[FN256] In the event the contract entered into requires less than a 3 percent increase or there are funds remaining after application of the any contractual increase, any excess funds remaining in the account, or which would otherwise accrue shall be reported to the Commission and deposited into the IFR restricted account.

FN255. Commission Exhibit 1 (Providence Water Response to Commission Data Request 3-12); Providence Water Response to Commission Record Requests 5, 6 (dated September 21, 2007). Tr. 9/12/07, pp. 121-22.

FN256. Benefits includes union combined benefits and laborers' international pension.

Providence Water requested a 3 percent net operating revenue allowance and agreed with KCWA's proposal to restrict a portion of it to cover shortfalls resulting from reduced revenues and the remainder unrestricted to cover unanticipated expenses. The Division recommended maintaining the 1.5 percent net operating revenue reserve previously allowed to Providence Water in light of the Commission's recent decision in Docket No. 3818 to deny a requested increase in Newport Water Department's operating revenue allowance pending the outcome of a new docket to address the appropriateness and funding for such reserve.[FN257]

FN257. Public Utilities Commission, Minutes of Open Meeting, August 30, 2007.

By a decision of 2-1, Providence Water is allowed a 3 percent net operating reserve, with 2 percent of it restricted to cover revenue shortfalls resulting from reduced consumption once Providence Water demonstrates to the Commission the need for such funds as a result of reduced sales levels. However, because the State of Rhode Island has made it a priority to encourage conservation, the Commission is requiring Providence Water to file a rate proposal on or before July 1, 2009 which includes proposed conservation rates. If Providence Water fails to file such a proposal by that date, the 2 percent revenue reserve will end at July 1, 2009, and Providence Water shall immediately file with the Commission to adjust rates to eliminate collection of the 2.0 percent revenue reserve for usage on and after July 1, 2009. The Commission notes that Providence Water advocated many rate design proposals which would shift more costs from consumption based rates to fixed service charges. While the Commission recognizes Providence Water's desire for such revenue stability, conservation is an equally important goal. With the allowed operating revenue allowance, Providence Water should be able to find an appropriate balance between expenses and revenues.

The Commission recognizes the impact of fluctuating sales on revenues which puts pressure on the non-investor owned water utilities to manage expenses. While weather has a big impact on usage and sales, so too does conservation, which is a priority of the State of Rhode Island. As conservation becomes more important and customers take measures to reduce their usage, revenues are reduced while many fixed costs remain in place. When sales are reduced, either due to weather or conservation, some expenses are likewise reduced. However, items such as capital projects, infrastructure, and personnel expenses resulting from labor contracts not within the control of the water utility management do not decrease. Therefore, like other non-investor owned water utilities, Providence Water experiences challenges in funding restricted accounts such as IFR and Capital Improvements due to prioritization of bills. When this occurs, the competing interests of conservation and the desire to keep rates low collide as water utilities petition the Commission for rate increases to cover increased costs and reduced sales. Of course, not all water utilities are the same. Some have been experiencing clear downward trends in water sales while others, like Providence Water have been experiencing fluctuations from year to year. In addition, looking at Providence Water in light of long-standing Commission policy to attempt rate stabilization, the Commission believes that a net operating revenue reserve of 3 percent with 2 percent restricted, continuation of which is contingent upon filing a conservation rate, will further this policy.

E. Cost Allocations and Rate Design

Providence Water proposed a fixed, monthly wholesale service charge based on 25 percent of the wholesale customer's revenues. The Division did not oppose this fixed charge because the Division agreed with Providence Water that this would improve revenue stability from the wholesale class. KCWA opposed the fixed charge for the following reasons: (1) as water use among wholesale customers changes, the fixed charge will result in rates that are not cost-based and (2) that allocating 25 percent of wholesale revenues to a fixed charge results in a lower commodity rate which provides less incentive to conserve.[FN258] The Commission agrees with KCWA's analysis and rejects Providence Water's proposal.

FN258. The Commission also notes that at the hearing, when asked to explain a provision of his surrebuttal testimony, Mr. Woodcock stated that “general, higher meter based or consumption charges give customers more control over how much their total water bills are versus a fixed service charge where it doesn't matter how much water they use, so the higher the consumption based charge, the greater the conservation incentive there is.” Tr. 9/13/07, p. 232.

Providence Water proposed to decrease the demand costs allocated to fire service by 50 percent and recover this amount from other customers through consumption rates. Providence Water's main argument in favor of this change was that the City of Providence is home to several tax exempt properties and it is unfair that they do not have to pay public fire protection charges which are collected by the City through property taxes. The Division and KCWA opposed the change. Three reasons provided were: (1) it reduces the cost allocations to private service, requiring general water service customers to bear a portion of private fire service; (2) IFR costs are not allocated to fire service charges under state law, resulting in a subsidy to fire protection services; and (3) it provides less revenue stability in contradiction to Providence Water's goal. On cross examination, Providence Water's witness conceded that this change was a policy decision by Providence Water rather than a better cost based methodology than had been used before. Providence Water's witness also conceded that, assuming Commission policy has been to try to bring public and private fire protection closer to their respective actual cost of service, Providence Water's proposal “does not necessarily coincide with that policy.”[FN259]

FN259. Tr. 9/13/07, p. 196.

The Commission notes that since 2000, it has been a policy objective of the Commission to bring public and private fire service rates in line with their respective actual cost of service.FN260 However, the Commission also did not want to cause rate shock to the public entities collecting such charges through property taxes. Therefore, the Commission has been requiring Providence Water to hold private fire service rates level and increase public fire service rates incrementally over the past seven years.FN261 Providence Water has presented no evidence to persuade the Commission to deviate from this stated policy. In fact, the Commission questions whether Providence Water's rationale for arbitrarily reducing the demand by 50 percent is a reasonable basis upon which the Commission could change its policy.FN262 Furthermore, the Commission is persuaded by the rationale posited by the Division not to reduce the demand and further adds that fire protection is a city responsibility and if there is an abandoned building, the city is not going to refuse to put out the fire because the taxes are overdue.FN263 For all of these reasons, the Commission rejects Providence Water's proposal to reduce demand costs allocated to fire service by 50 percent.

FN260.*Order No. 16552* (issued March 27, 2001), *Order No* (issued January 11, 2006).

FN261. In *Order No*. 17344, p. 19, the Commission stated, “Despite this increase, the public fire rates would still be below the cost of service for public fire service.”(citations omitted). As quoted in *Order No*. 18496, p. 13, the Division's witness opined that “‘it's probably that the public hydrant charge is tool low, [and] it may not be that the private fire service charge is too high compared to costs.”' (citations omitted).

FN262. The Supreme Court has indicated that the Commission cannot review the ability to pay as a basis for setting rates. *See Narragansett Electric Co. v. Harsch*, 117 R.I. 395, 427-30, 368 A.2d 1194 (R.I. 1977) (stating that in setting the utility's return on equity, “that specific reliance by the commission on the consumers' ability to pay is error).

FN263. As a side note, the Commission notes that through discovery, it became apparent that the City of Providence is receiving a Payment in Lieu of Taxes from tax exempt organizations in the amount of $1 million per year. Whether or not this is sufficient compensation for the services those entities received is not for Commission consideration. However, those entities are contributing to the City. (Commission Exhibit 1, Annual Reports of the City of Providence).

While Providence Water's initial filing did not include an allocation for lost and unaccounted for water, the Division utilized the inch-mile method and Providence Water did the same in its Rebuttal. This approach is consistent with prior cost studies and with prior Commission orders. KCWA suggested the Commission consider a different approach which it claimed would take into account losses of water from service mains. Providence Water and the Division objected to the new approach, citing the fact that KCWA really presented this approach in its Surrebuttal. KCWA argued that although this is a new approach, it would more accurately allocate lost and unaccounted for water and the Commission should not approve a methodology simply because it had been used in the past. The Commission allowed Providence Water and the Division the opportunity at the hearing to rebut KCWA's position through additional direct testimony and to cross examine KCWA. The Commission finds that KCWA did not present sufficient evidence to support its methodology in this docket. However, the Commission agrees that if there are alternative methodologies for allocating lost and unaccounted for water in a more accurate manner, they should be considered. Therefore, the Commission accepts the continued use of the inch-mile method for purposes of this rate case. However, in the next case, Providence Water is directed to also consider whether there is another methodology that would more accurately allocate lost and unaccounted for water. KCWA is also reminded to present its positions in its Direct Testimony and not wait for the Surrebuttal stage.

Providence Water proposed allocating the pension costs and fringe benefits of personnel in the Customer Accounts cost center to Meters/Service and Billing/Collections. This results in 50 to 70 percent increases in customer charges. The Division opposed that allocation of costs, noting that the Commission had previously rejected such cost allocation in order to allocate a larger amount of the revenue requirement to consumption based rates. The Division proposed continuing to reallocate these costs to the “Base” category so as to minimize fixed rates and increase commodity rates that provide a price signal to customers to encourage conservation and reduce their billings. KCWA supported Providence Water's allocation as the appropriate methodology. The Commission notes that this allocation represents a decision of whether or not to continue following a prior policy. While Providence Water's proposal may be more technically correct, the Commission declines to accept it for the same reasons it made the change previously. In addition, the Commission notes that the Division's allocation will still result in a 30 percent increase in the residential quarterly service charge, not an insignificant amount to be collected through a fixed charge that does not encourage conservation.

KCWA proposed allocating labor and power costs related to pumping separately from treatment costs because Providence Water's Pumping costs do not reflect any allocation of labor. The Division agrees with KCWA's position. The Commission accepts KCWA's allocation of labor and power costs related to Pumping. KCWA also proposed that the capital fund related to the Western Cranston expansion be allocated entirely to retail customers because none of the project serves wholesale customers. Providence Water agreed in its rebuttal. The Division disagreed, maintaining that over time, the payment of debt or rate funded capital will generally be in proportion to the asset values. The Commission notes that the dollar amount involved in this disagreement is $62,069 and accepts KCWA's argument and approach as adopted by Providence Water on the basis that the Western Cranston Capital Fund does not appear to benefit wholesale customers. The Commission notes that this is a somewhat unique situation. In most cases, costs related to system expansions are shared by all customers because it can be shown that all customers benefit to some extent from the increased customer base. Therefore, the Commission does not anticipate this becoming a generalized policy. Finally, KCWA proposed an adjustment to the allocation of Miscellaneous revenues on the basis that rental income is derived from easements on supply land and therefore, the rental revenues should be allocated to supply using the supply allocator. Because of the de minimus nature of the rental income ($20,000 to a total of $1,245,739 in miscellaneous revenues), the Commission will not require the adjustment to be made, noting that this would be a deviation from the methodology used in prior approved cost studies.

Accordingly, it is hereby

(19145) ORDERED

1. Providence Water Supply Board's Rate Filing of March 30, 2007, is hereby denied and dismissed.

2. Providence Water Supply Board is granted a revenue increase of $6,935,500, for a total cost of service of $58,086,064 to be applied to usage on and after November 1, 2007.

3. The compliance tariffs filed by the Providence Water Supply Board on October 7, 2007 are hereby approved.

4. The Providence Water Supply Board shall continue to restrict the following accounts in the following amounts collected through rates: Capital Improvements - $2,450,000; Western Cranston Fund - $62,069; IFR - $13,900,000; Meter Replacement - $1,000,000; Insurance Fund - $2,967,655; Chemicals and Sludge - $3,132,565; and Equipment Replacement - $600,000. In addition, Providence Water Supply Board shall restrict the following amount in a separate account - Property Tax Refund - $1,510,096.16. Providence Water shall report on the funding of its restricted accounts every four (4) months.

5. Providence Water shall also restrict the equivalent of a 3 percent increase in salaries ($947,203) for the purpose of covering anticipated salary increases when a new labor contract is entered into between the City of Providence and Public Employees' Local Union 1033.

6. Out of the Property Tax Refund account, $375,000 shall be credited to customers annually, for a total over three years of $1,125,000. The remaining balance in the account shall be used for litigation expenses related to property tax challenges, but not increased property taxes. Funds may be expended only on invoices for services rendered on and after November 1, 2007. In conjunction with its semi-annual financial report, Providence Water shall provide to the Commission, with a copy to the parties to this docket, a reconciliation of the activity in the account. Any future tax refunds or adjustments in Providence Water's favor shall be deposited into this account for further disposition as ordered by the Commission.

7. Providence Water Supply Board shall file its semi-annual reports no later than ninety (90) days after the respective reporting period ends.

8. Providence Water Supply Board shall include in its semi-annual reports a line item that breaks out capitalized labor in its reports on IFR and CIP projects. Providence Water Supply Board shall also include the following: Pensions: amount of contribution, percentage of actuarial recommendation compared to the City's and the School Department's, any changes to the pension plan, the cost of the pension contribution as a percentage of actual payroll of those who are in the pension system, and once per year, shall provide the annual report from Providence Water' actuary on the pension plan and the annual audited report on the pension plan. Retiree Health Care Reporting related to GASB 43/45 actuarial recommendations: amount of contribution, percentage of the actuary's recommendation compared to the City's and the School Department's. Any amounts allowed in rates in excess of the actual contributions shall be restricted.

9. The Providence Water Supply Board is allowed a 3.0 percent net operating reserve. Two percent of the reserve shall be restricted and may only be used to cover shortfalls in allowed revenues upon a showing by Providence Water Supply Board that the shortfall resulted from reduced consumption. Providence Water Supply Board shall file a rate proposal on or before July 1, 2009 which includes proposed conservation rates. In the event Providence Water Supply Board fails to make such a filing, the 2 percent reserve shall cease and Providence Water Supply Board shall immediately file to adjust rates to eliminate collection of the 2 percent Revenue Reserve for usage on and after July 1, 2009.

10. Providence Water Supply Board's request to fund through future rates repayment of the City of Providence $1,489,081 over six years, or $248,180 annually for past retiree health care expense is denied.

11. Providence Water Supply Board's proposal to reduce demand allocated to fire protection by 50 percent is denied.

12. For purposes of this rate case, City Service Expense is set at $839,167.

13. The Providence Water Supply Board shall comply with the reporting requirements and all other terms, conditions, and instructions imposed by this Report and Order.

EFFECTIVE AT WARWICK, RHODE ISLAND ON NOVEMBER 1, 2007 PURSUANT TO OPEN MEETING DECISIONS ON OCTOBER 30, 2007, NOVEMBER 8, 2007. WRITTEN ORDER ISSUED DECEMBER 13, 2007.

PUBLIC UTILITIES COMMISSION

Elia Germani, Chairman

Robert B. Holbrook, Commissioner

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*Mary E. Bray, Commissioner

* Commissioner Bray dissented from the majority, indicating that while she agreed in principle with the reasoning provided by the majority, she did not believe a basis existed for treating Providence Water differently from Newport Water Department absent a determination in the generic docket.

NOTICE OF RIGHT OF APPEAL: PURSUANT TO R.I.G.L. § 39-5-1, ANY PERSON AGGRIEVED BY A

DECISION OR ORDER OF THE COMMISSION MAY, WITHIN SEVEN (7) DAYS FROM THE DATE OF THE DECISION OR ORDER, PETITION THE SUPREME COURT FOR A WRIT OF CERTIORARI TO REVIEW THE LEGALITY AND REASONABLENESS OF THE DECISION OR ORDER.

Appendix A

Providence Water Supply Board Docket 3832 - Cost of Service

	PWSB Position	Commission Adjustments	Proforma Cost of Service
Revenues			
Retail Water Sales	$ 30,026,250		$ 30,026,250
Wholesale Water Sales	13,180,648		13,180,648
Retail Service Charges	3,914,325		3,914,325
Private Fire Service	1,266,618		1,266,618
Public Fire Service	1,516,984		1,516,984
Miscellaneous Income	1,245,739		1,245,739
Total Revenues	$ 51,150,564		$ 51,150,564
Expenses			
Operation and Maintenance	$ 26,866,182	$ (246,080)	$ 26,620,102
Insurance[a1]	2,967,655		2,967,655
Chemical & Sludge[a1]	3,132,565		3,132,565
City Service Expenses	1,240,355	(401,188)	839,167
Property Taxes	5,843,681		5,843,681
Capital Labor	(984,719)	-	(984,719)
Total Operating Expenses	$ 39,065,719	$ (647,268)	$ 38,418,451
Capital Funds			
Capital Improvement Fund [a1]	$ 2,450,000		$ 2,450,000
Western Cranston Fund[a1]	62,069		62,069
Infrastructure Replacement [a1]	13,900,000		13,900,000
Meter Replacement[a1]	1,000,000		1,000,000
Equipment Replacement[a1]	600,000		600,000
Total Capital Funds	$ 18,012,069		$ 18,012,069
Total Expenses	$ 57,077,788	$ (647,268)	$ 56,430,520
Net Operating Reserve	$ 1,674,961	$ (1,123,113)	$ 551,848
Revenue Reserve[a1]	-	1,103,696	1,103,696

Total Cost of Service	$ 58,752,749	$ (666,685)	$ 58,086,064
Rate Year Revenues at Present Rates			51,150,564
Revenue Increase			$ 6,935,500

a1. Restricted Funding Account

Appendix B

Providence Water Supply Board Docket 3832 Cost of Service Adjustments

	Increase / (Decrease) In Amounts
Operation and Maintenance Expenses	
Disallowance of amount to pay prior years' retirees' health care costs	$ (248,180)
Increase in O & M expense for conservation notice	2,100
Total Operation and Maintenance Expense Adjustment	$ (246,080)
City Service Expenses	$ (401,188)
Net Operating / Revenue Reserves	
Reduction in Net Operating Reserve to 1% level	$ (1,123,113)
Provision for Revenue Reserve at 2% level	$ 1,103,696

END OF DOCUMENT

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 06-E-1433 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

CASE 06-E-1547 - Petition of Orange and Rockland Utilities, Inc. Regarding Disposition of Property Tax Benefits from the Towns of Haverstraw and Orangetown.

ORDER SETTING PERMANENT RATES, RECONCILING OVERPAYMENTS DURING TEMPORARY RATE PERIOD, AND ESTABLISHING DISPOSITION OF PROPERTY TAX REFUNDS

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on October 17, 2007

COMMISSIONERS PRESENT:

Patricia L. Acampora, Chairwoman
Maureen F. Harris, dissenting
Robert E. Curry, Jr.
Cheryl A. Buley

CASE 06-E-1433 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

CASE 06-E-1547 - Petition of Orange and Rockland Utilities, Inc. Regarding Disposition of Property Tax Benefits from the Towns of Haverstraw and Orangetown.

ORDER SETTING PERMANENT RATES, RECONCILING OVERPAYMENTS DURING TEMPORARY RATE PERIOD, AND ESTABLISHING DISPOSITION OF PROPERTY TAX REFUNDS

(Issued and Effective October 18, 2007)

BY THE COMMISSION:

INTRODUCTION

By this order, we establish permanent electric rates for Orange and Rockland Utilities, Inc. (Orange and Rockland or the Company). Rates will be unchanged from those currently in effect, so that Orange & Rockland’s tariff will not change except for the removal of its temporary status. However, we are increasing the allowance included in rates for the costs of pensions and other post-employment benefits (OPEBs) incurred by Orange and Rockland. Consequently, it is likely that the Company’s prospective earnings will appropriately be nearer to the allowed return established herein, rather than at the excessive levels experienced by the Company most recently.

Our concern regarding excessive earnings by the Company, resulting in rates that were not just and reasonable, led us to institute this case and to make Orange and Rockland's rates temporary as of March 1, 2007. In this order, we determine that ratepayers have overpaid since March 1, 2007 and order that such overpayments be applied to the deferred balances due for pension and OPEB expense.

Also in this order, we address Orange and Rockland's petition regarding the disposition of tax benefits received as a result of its litigation with the Town of Orangetown and the Town of Haverstraw. We will allow the Company to retain 10% of those net benefits for shareholders as recognition and incentive for the Company to undertake such efforts to reduce its costs.

PROCEDURAL HISTORY

We have considered this case on several previous occasions. We instituted the proceeding by Order to Show Cause on December 15, 2006. Thereafter we issued an order on interlocutory appeals regarding the schedule for consideration of temporary rates, requiring the matter to be ready for our consideration in February of 2007.[1] Following our February session, we made Orange and Rockland's electric rates temporary at their current levels by order issued March 1, 2007. We also denied a petition for rehearing of the Order Concerning Interlocutory Appeals by our order dated May 18, 2007. The relevant procedural developments leading to each of those orders is set forth in them, and we will not repeat it here.

Consequently, we will recount the procedural history that begins with the establishment of procedures and a schedule for consideration of permanent rates in this case. After canvassing the parties, the presiding ALJ issued a ruling

[1] Order Concerning Interlocutory Appeals (issued February 1, 2007).

establishing the schedule for consideration of permanent rates on March 8, 2007. Pursuant to that ruling, the Company filed supplemental and updated testimony on March 16, 2007. Staff filed responsive testimony on May 3, 2007, and Orange and Rockland submitted rebuttal testimony on May 10, 2007.

Meanwhile, on December 19, 2006, Orange and Rockland had filed a petition pursuant to Public Service Law (PSL) §113 regarding the disposition of property tax benefits from the Towns of Haverstraw and Orangetown in Rockland County, in which the Company asked that property tax benefits allocable to Orange and Rockland's electric service be shared by the Company and its customers. That petition was assigned Case No. 06-E-1547. On April 11, 2007, DPS Staff Counsel, by letter to the ALJ presiding in Case 06-E-1433 served on all parties in both cases, requested that the hearing on the property tax petition be held in conjunction with the hearing in Case 06-E-1433. Orange and Rockland consented to this process, and no other party objected to the consolidation of the two cases for hearing purposes. Consequently, Staff included its analysis and recommendation regarding the Company's property tax refund petition in its May 3, 2007 pre-filed testimony, and Orange and Rockland's May 10, 2007 rebuttal testimony included a response on the property tax issue.

Thereafter, the parties engaged in a series of settlement negotiations in an attempt to resolve all pending issues. Based on representations by the parties that those negotiations were productive, the schedule for conducting an evidentiary hearing to consider the pre-filed testimony was postponed several times in rulings and corresponding notices issued May 18, 2007, June 1, 2007, June 11, 2007 and June 20, 2007. When it was determined that the settlement negotiations would not lead to resolution of the case, the litigation schedule was resumed, and the parties appeared before the ALJ for evidentiary hearings on July 11, 2007 and July 13, 2007. As noted, those hearings included testimony and cross-examination on the issues pending in both Case 06-E-1433 and Case 06-E-1547.

Pursuant to a briefing schedule established at the conclusion of the evidentiary hearings, as subsequently modified on request of a party, the parties submitted post-hearing briefs on August 3, 2007 and reply briefs on August 10, 2007. Initial briefs were submitted by Orange and Rockland, Department of Public Service Staff, the Town of Ramapo by Supervisor Christopher P. St. Lawrence, and the New York State Consumer Protection Board (CPB). Reply briefs were received from Orange and Rockland and Staff.[2]

On July 2, 2007, Orange and Rockland filed a petition and complaint pursuant to CPLR Article 78 in the New York State Supreme Court of Albany County seeking a judgment and order annulling and vacating the temporary rates order. At present, that case remains pending before the state court.

Notice of these cases has been published in the New York State Register. In addition, a Notice and press release soliciting comments were issued in August of 2007. No non-party comments have been received.

RATE OF RETURN

Capital Structure

Staff and the Company have two disputes regarding the appropriate capital structure to be used to calculate the rate of return in this case. First, whereas Orange and Rockland relies on its stand-alone capital structure, without regard to

[2] As set forth in a July 30, 2007 Ruling Establishing Procedures for Consideration of Revenue Decoupling and Energy Efficiency on July 30, 2007, consideration of a revenue decoupling mechanism and the specifics of an energy efficiency plan for Orange and Rockland will occur in a further phase of Case 06-E-1433.

its corporate parent, Consolidated Edison, Inc. (CEI), Staff readjusts Orange and Rockland's capital structure in light of all of CEI's holdings, attributing similar equity ratios for both regulated and non-regulated subsidiaries. Second, Staff and the Company present information at different points in time and dispute which information should be considered in making a forecast for the rate year ending June 30, 2008. We will address each of these issues in turn.

We will adopt Staff's adjustments to Orange and Rockland's capital structure to reflect the consolidated capital structure of its parent holding company. Staff's adjustment provides the more realistic estimate of the appropriate ratios on which to develop Orange and Rockland's overall cost of capital. This practice is consistent with the approach we followed recently in setting rates for New York State Electric and Gas Corporation and with the other precedents cited in that order.[3] We are not persuaded to deviate from this established practice by the arguments Orange and Rockland raises here.

The Company notes that both Moodys and Fitch establish their bond ratings for Orange and Rockland based on its stand-alone corporate structure. While the rating agencies are entitled to exercise their judgment in carrying out their evaluations, their practices are not binding or dispositive for us in our ratemaking practices. In any event, we note that Standard & Poors relies on the consolidated entity to determine its ratings. Further, even those agencies that rate Orange and Rockland separately from its corporate parent consider the financial and business position of the parent when establishing the subsidiary's bond rating.

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[3] Case 05-E-1222, New York State Electric and Gas Corporation-Electric Rates, Order Adopting Recommended Decision with Modifications (issued August 23, 2006), p. 87.

Orange and Rockland also argues that Staff's position is inconsistent with our recent adoption of a joint proposal in a Consolidated Edison steam case, in which the capital structure was established on a stand-alone basis for Consolidated Edison Company of New York.[4] We do not regard that order as an expression of general policy regarding capital structure. Cases presented to us as joint proposals based upon settlements among the parties reflect numerous trade-offs and, therefore, must be considered as a whole. In such a case, the resolution of a particular item such as capital structure does not establish a precedent or our definitive policy on that particular issue.

We also find Staff's forecast to be more accurate in other respects. Staff forecasts capital structure for the year ending June 30, 2008 by starting with the structure for December 31, 2006, and then updating for later events reflected in forecasts submitted by Company witnesses in the Con Edison gas rates proceeding.[5] Staff assumes that such changes for the forecast rate year would result in an increase of $66.8 million of Orange and Rockland common equity for the second quarter of 2007.[6] That level of increase would bring the Company's common equity to a level consistent with the equity ratio forecast by Company witnesses.[7]

In contrast, the Company appears to rely upon capital structure information that was submitted in the temporary rate phase of this case for the year ending December 31, 2007. Although the Company purported to submit an updated filing for

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[4] Case 05-S-1376, Consolidated Edison Company of New York, Inc. – Steam Rates, Order Determining Revenue Requirement and Rate Design (issued September 22, 2006).

[5] Tr. 1033, citing testimony of Company Witness Cunha in Case 06-G-1332, Consolidated Edison Company of New York, Inc.-Gas Rates.

[6] Tr. 1032.

[7] Id.

the rate year ended June 30, 2008, that presentation is identical to what was presented for the year ending December 31, 2007.[8] As a consequence, only Staff's presentation accounts for the proper time period on which our rate determination here is based. We therefore rely upon Staff's capital structure presentation.

Cost of Debt

Staff and Orange and Rockland differ in their cost of debt calculations due to differing estimates for the cost of an issuance of 10-year debentures contemplated for September 2007. Because the issuance has not yet occurred but is still contemplated, we must select the most appropriate forecast in lieu of the unknown actual cost. We also take into account the delay in issuance by reducing the time during the rate year that the debt is outstanding by one month.

The Company's presentation estimates the cost for this debt issuance based on Blue Chip Financial Forecasts of Treasury rates and a spread to that Treasury rate "based on current spreads in the near term and average historical spreads for later periods." The result is an interest rate for the new debentures of 6.48%.

Staff asserts that the Company's estimate results in a spread above Treasury rates of 176 basis points, which Staff views as excessive.[9] Staff instead calculated the cost of the September 2007 debt issuance by using an 83 basis point spread above the Treasury rate, to mirror the spread above the Treasury rate reflected in the Company's debt issuance of October 2006.

Neither estimate is consistent with current market conditions. Moody's Credit Perspectives reports a current

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8 Staff Initial Brief, at 29. See Ex. 27, E-10, p. 15; Ex. 27, E-11, p. 13; Ex. 27, E-13, p. 1 (using the same capital structure for years ending December 31, 2007, December 31, 2008, and June 30, 2008).

9 Staff Reply Brief at 15; Staff Initial Brief at 32.

spread of about 130 basis points on bonds of similar credit quality to Orange and Rockland. We updated our cost of debt estimate for Orange and Rockland consistent with the latest information on spreads and Treasury rates. The overall cost of debt based upon this information is 6.24%.

Cost of Equity

The evidence in this proceeding indicates the parties' understanding and agreement that the cost of equity should properly be set at a level that will furnish sufficient earnings to assure the financial integrity and creditworthiness of the firm in order to attract capital on reasonable terms. These standards are well established by court precedents such as Bluefield Waterworks[10] and Hope.[11] Those parties submitting testimony regarding an appropriate return on equity (ROE) generally support a combination of methods, rather than reliance on a single method of computing ROE. Thus, both the Staff and Company witnesses perform analyses using the discounted cash flow (DCF) and the capital asset pricing model (CAPM) methodologies. Orange and Rockland also employs a third risk premium analysis. Both Staff and the Company rely on the use of proxy groups in conducting their analyses. The use of more than one method applied to proxy groups tends to correct for aberrations that might otherwise skew results if one specific approach were applied solely to the utility for which the Commission was setting rates.

The disagreements between Staff and the Company relate to the technical application of the various methodologies, the selection of the proxy groups, and the use of other data inputs necessary to the calculations. Staff generally follows the

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[10] Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

[11] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 391 (1944). Bluefield and Hope are cited by Orange and Rockland witness Morin at Tr. P-724-25.

methodology recommended by the Recommended Decision in the Generic Finance Proceeding,[12] arriving at an ROE recommendation of 8.95%. CPB and Ramapo support and adopt the Staff position.[13] Orange and Rockland performs some alternative calculations and arrives at an ROE of 11.2%. Based on our analysis of this record, we find that an appropriate allowed ROE for Orange and Rockland is 9.1%, as discussed below.

1. Discounted Cash Flow (DCF)

Staff uses a two-stage methodology, making separate calculations of the forecasted growth in dividends in the short term and the long term sustainable growth in dividends.[14] The two-stage methodology is based on the calculation that was recommended in the Generic Finance proceeding Recommended Decision and has been generally employed in our cases. The calculation of long-run sustainable growth is based upon each proxy group company's projected earnings retention growth as well as the likely effect of future issuances of common stock.[15]

In contrast, Orange and Rockland uses a single-stage methodology, relying upon forecasts of earnings growth as a surrogate for future dividend growth. The Company is highly critical of the earnings retention growth calculation performed by Staff in the second stage of Staff's DCF analysis. According to the Company's testimony, there is circularity in this approach because an ROE forecast--i.e., the end result of the analysis--is used as a data input to implement the method.

Orange and Rockland's use of single stage earnings per share growth as the appropriate DCF growth rate is not reliable,

[12] Case 91-M-0509, Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for the New York State Utilities, Recommended Decision (July 19, 1994).

[13] CPB Initial Brief, p. 2; Ramapo Initial Brief, p. 4

[14] Tr. 1048.

[15] Id.

and we will not adopt it here. The company has not demonstrated any link between its earnings per share growth estimate and the future dividend growth of the proxy group based on the actual dividend pay-out policies of the companies in that group. Moreover, there is no evidence suggesting that Orange and Rockland's earnings growth rate estimate is sustainable over time.[16] The Company effectively concedes these points and supports the two-stage approach when it notes that it is widely expected that utilities will continue to lower their dividend pay-out ratios over the next several years.[17] Such declines in dividend pay-out ratios will typically result in declines in dividend growth. Consequently, short run dividend growth is likely to differ from longer run sustainable dividend growth.

Orange and Rockland's argument regarding the circularity of Staff's sustainable growth calculation is overstated. The retention growth component of the sustainable growth calculation relies on a prediction of expected future <u>earned</u> rates of return on common equity for a proxy group composed mainly of holding companies owning both regulated utilities and unregulated businesses. While these forecasts of expected future earnings will consider the return that investors expect regulators to allow for the utility subsidiaries, these earnings forecasts also reflect investor expectations about how a wide variety of other factors, unrelated to the <u>allowed</u> cost of equity, will affect the overall earnings of the holding company.

We also find the proxy group employed by Staff in its DCF calculation superior to the Company's proxy group. Staff carefully explains and supports its selection of comparable companies to make up the proxy group of companies used in the

[16] Tr. 1061

[17] Tr. 766.

DCF analysis.[18] Notably, Orange and Rockland does not challenge or criticize Staff's proxy groups, but merely offers its own alternative. In contrast, Staff is highly critical of the Company's proxy groups. The record here supports a finding that these groups are too risky because Orange and Rockland includes companies that do not receive 70% or more of their operating revenues from utility operations, companies that are not investment grade, and companies involved in various restructuring activities.[19]

We continue to endorse the annual DCF model used by Staff here. We reject Orange and Rockland's criticism that this model ignores the time value of quarterly dividend payments.[20] As Staff points out, we rejected this theory long ago.[21]

We also continue to support the use of six months' worth of stock prices as the input into the DCF calculation, rather than the current stock price. Orange and Rockland is correct in noting that such data can be stale.[22] Consequently, it might be appropriate to use current prices in conducting DCF analyses in other circumstances, and we would not necessarily reject such an input out of hand. However, use of the six-month data does serve to limit volatility, and it assures better alignment of the dividend yield calculation and the underlying data used to estimate investors' expected growth. Consequently, particularly in this case, where Staff has otherwise put forward a superior and reliable DCF analysis, we see no need to disturb

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[18] Tr. 1040-47.

[19] Tr. 1059-60.

[20] Orange & Rockland Initial Brief at 24.

[21] Cases 27651 & 27710, New York Telephone Company-Rates, Opinion No. 81-3 (issued January 19, 1981), cited in Generic Finance Recommended Decision, supra.

[22] Tr. P-795, Orange & Rockland Initial Brief at 24.

its calculation here to substitute the current price of stock as an input.

In sum, then, we adopt Staff's DCF calculation without change as one important component into the ROE calculation.

2. Capital Asset Pricing Model (CAPM)

Both Staff and the Company rely on the same methodology to perform their CAPM analyses. They disagree regarding the input for the market risk premium used in the analysis. The Company witness uses two sources for the market risk premium. The first source is data compiled in the study, *Stocks, Bonds, Bills, and Inflation, 2006 Yearbook*, produced by Ibbotson Associates, which includes historical returns from 1927 through 2005. The second source for the Company's market risk premium is a DCF analysis used to predict a prospective market risk premium, which the Company then averages with the historical Ibbotson figure. In contrast, Staff relies exclusively upon Merrill Lynch data published in Quantitative Profiles, containing the Market-Required Return for the S&P 500.[23]

Staff's calculation of the risk premium is superior here. As Staff explains, the Ibbotson data are stale and much less reliable than the up-to-date estimates available from Merrill Lynch. Although the Ibbotson data were relied upon in the Generic Finance RD, Staff explains that the Merrill Lynch publication was not available at the time of the Generic Finance RD and, since the Quantitative Profiles has been published, Staff has consistently recommended its substitution as a more preferable data source. For this reason, we have accepted use of the Merrill Lynch data, in our recent decision establishing

[23] Henry Testimony at 35.

rates for New York State Electric and Gas Corporation.[24] Staff also aptly criticizes the Company's forward-looking market risk premium calculation. The 11.27% dividend growth rate used in this method exceeds the total market return forecast by Merrill Lynch, and, without evidence to show that such a growth rate is sustainable, is unreliable.

On this record, there are serious criticisms that point to the unreliability of the Company's CAPM analysis. Staff's implementation of the method is therefore far more reliable and we adopt Staff's CAPM forecast.

3. Risk Premium Methodology

Staff did not conduct a further ROE analysis using the risk premium methodology, whereas Orange and Rockland submits two such analyses as part of its presentation. The Company's witness conducted a historical analysis for the industry as a whole, using Moody's Electric Utility Index.[25] Orange and Rockland then conducted a second, forward-looking analysis, relying on Regulatory Associates' Regulatory Focus to compare allowed returns of other utilities. Staff criticizes both of these methods for their failure to evaluate how Orange and Rockland compares with other utilities being studied. In response to Staff's criticism regarding the historical study, the Company asserts that Orange and Rockland is at least as risky as the average electric utility.[26] On reply, Staff asserts that this statement is incredible, given that the average debt rating for the industry as a whole is three full notches lower than the debt rating for Orange and Rockland.

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[24] Case 05-E-1222, New York State Electric and Gas Corporation-Rates, Order Adopting Recommended Decision with Modifications (issued August 23, 2006); see also Case 95-G-1034, Central Hudson Gas & Electric Corporation-Rates, Opinion No. 96-28 (issued October 3, 1996).

[25] Orange & Rockland Initial Brief at 27.

[26] Tr. P-810.

We agree with Staff that the hazards of comparing apples and oranges make the Company’s risk premium analysis too unreliable to use in this proceeding. The significant differences among utilities and among the ways that allowed returns are set by regulatory commissions render such comparisons unreliable, absent careful effort and analysis to ensure comparability. For this reason, we will reject the risk premium methodology analysis proffered by Orange and Rockland and will rely instead solely on the DCF and CAPM analyses on this record.

4. Appropriate Weighting of ROE Methods

Orange and Rockland argues that the DCF methodology has inherent flaws such that it is inappropriate to accord it undue weight. Instead, Orange and Rockland proposes equal weighting of the DCF, CAPM and risk premium analyses it has performed. As noted above, we are forced to disregard the Company’s risk premium analyses as too unreliable for use in this proceeding. Instead, we will take the results of Staff’s DCF and CAPM analyses to make our ROE determination.

We will continue to accord two-thirds weight to the DCF result and one-third to the CAPM result as we have in past decisions. This result is consistent with the recommendation of the co-facilitators in the Generic Financing proceeding. We note some of the concerns raised by Orange and Rockland regarding undue weight on the DCF methodology. Many of these concerns are addressed by the two-stage DCF method employed by Staff. Moreover, the method offers the significant benefit of reliance on readily available, objective data to measure an indicator of real importance to investors.

Our decision to retain the current weighting of the two approaches is also based on concerns we have regarding the application of the CAPM. It is our general observation that, while the business risks of New York’s electric utilities have declined as generation assets have been divested, the betas of the holding companies owning electric utilities have in fact increased. While this increase in the volatility of holding company stock prices relative to the market could reflect increased utility risk, it could just as easily be attributable to the higher risks of holding company non-utility businesses. Also, it is possible that earnings volatility in the utility industry may be reduced in the future, if the industry adopts revenue decoupling mechanisms similar to those now under consideration in New York. Given concerns such as these, we are not now inclined to deviate from our long-held view that the CAPM methodology should not be entitled to more than one-third of the weight in our ROE determination.

5. Flotation Costs

There is a dispute between Staff and the Company as to the appropriate amounts to include in the ROE calculation to account for the cost of stock issuance. Whereas Orange and Rockland’s witness includes 30 basis points to account for all issuance costs, both past and future, the Staff witness includes only nine basis points to anticipate an actual issuance during the forecast rate year. We will accept the Staff adjustment. Traditionally, we have only allowed recovery of such costs when there is a reasonable expectation that such costs will be incurred. The Company’s attempt to reach back to past issuances is supported only by a hypothetical statement that such costs may not have been collected, rather than any proof to that effect.

6. Summary of ROE Analysis

Relying on the analysis presented by Staff, including the 2/3rds-1/3rd weighting of the DCF and CAPM methods, adopting Staff’s credit quality adjustment and its estimate of flotation costs, we arrive at an allowed return on equity for the Company of 9.09%, which we will round up to 9.1%.

Summary of Overall Rate of Return

Based upon the foregoing discussion, we calculate Orange and Rockland's overall rate of return for the rate year as follows:

Component	Percentage	Cost Rate	Weighted Average
Long-Term Debt	49.95%	6.24%	3.12%
Customer Deposits	1.26	3.65	0.05
Preferred Stock	1.25	5.34	0.07
Common Equity	47.54	9.10	4.33
	100.00%		7.56%

EXPENSES

Labor Expense

The Company's presentation in this case includes an increase in labor expense for additional personnel to implement a new circuit reliability program and an emergency management and preparedness initiative. Staff accepts these expenses without adjustment, and we agree they are supported by the record. There remain disputes regarding (1) the impact of the Company's overhead line training program on its workforce of linemen, and (2) the scope of a productivity adjustment to be applied here.

1. Number of Linemen

Orange and Rockland proposes an adjustment in the budget for linemen of $316,000 to account for the employment of 10.5 additional linemen positions. It arrives at this figure by comparing the average employee level for the 12 months ended June 30, 2006 of 202.5 and comparing it with the actual employee level as of December 31, 2006, which was 213.[27] Staff asserts that levels as of December 31, 2006 are unusually high, due to the recent completion of the overhead line training program. Staff asserts that, since the training program is intended to maintain employee levels by replacing anticipated retirements,

[27] Tr. P-700-P-702; Staff Initial Brief at 9.

it is reasonable to anticipate a decline after December 31, 2006.[28] According to Staff, the employee level for the 12 months ending April 2007 averages 208. Consequently, on brief, Staff revises the initial position it put forth in testimony and supports an adjustment of an additional 5.5 positions to increase the budget by $166,000.

According to Orange and Rockland, its recent linemen training program, while ultimately intended to replace retiring workers, will result in an overall increase in the workforce in the short term. The Company notes that 20% of its employees are 55 or over and eligible for retirement, and an additional 20% of employees fall between the ages of 50-55.[29] It takes three and a half years for linemen to achieve the capability to perform live line work. Therefore, the Company explains, it is necessary to bring on new employees now in order to have a fully qualified staff when existing employees retire.

We will adopt the Company's normalizing adjustment of $316,000 rather than the Staff allowance of $166,000. The phenomenon of an aging workforce pervades the electric utility industry. Orange and Rockland appears to be taking proactive steps to ensure an appropriate transfer of knowledge to newer employees before its most experienced linemen retire. If, in the short term, this necessitates an increase above of what otherwise would be optimum staffing levels, we are supportive of those levels at this time to encourage appropriate training.

Of course, by building the higher number into rates at this juncture, we run the risk that rates will be overstated in the future as employee levels may ultimately decline at Orange and Rockland. We are confident that there will be an opportunity to reassess the number of linemen in setting rates for Orange and Rockland at some appropriate juncture in the

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[28] Tr. P-892; Staff Initial Brief at 10.

[29] Tr. P-707.

future, however. Any correction in the appropriate number of linemen can be made at that future time. To aid us in that future assessment and to ensure that Orange and Rockland's efforts are successful, we will require Orange and Rockland to report to Staff its employee counts in this category through June 30, 2008.

2. Productivity Adjustment

In its updated testimony proposing permanent rate levels in this proceeding, the Company noted that this Commission traditionally imposes a one percent productivity adjustment upon the labor budget to account for anticipated productivity. Staff and the Company differ only as to the scope of this adjustment. Whereas the Company applies the one percent factor solely to wage rates, Staff applies the adjustment to a broader base of labor costs, fringe benefits and payroll taxes.[30]

According to Orange and Rockland, it is inappropriate to extend the adjustment to benefits, since reduction of benefits would imply an actual reduction in employees (rather than, for example, reduction in overtime).[31] Orange and Rockland further asserts that application of the adjustment to pensions and OPEBs violates the Commission's Policy Statement on Pensions and OPEBs, which provides for deferral and full payment of such costs.[32]

Staff is correct that our longstanding practice is to apply the productivity adjustment to total employment

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[30] Tr. P-894.

[31] Orange and Rockland Initial Brief at 11-12.

[32] Orange and Rockland Initial Brief at 12 citing Case 91-M-0890, Development of a Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pension and Post Retirement Benefits Other Than Pensions, Statement of Policy and Order (issued September 7, 1993)(Policy Statement on Pensions and OPEBs).

compensation, including wages and benefits.[33] As Staff notes, the adjustment is a surrogate for specific adjustments to overall productivity gains. It is not intended to equate directly to either reduction in employee levels or denial of recovery of pension, OPEB, or any other benefits expense.[34] Consequently, we will adopt the full Staff adjustment of $112,000.

Tree Trimming

While Staff accepts the majority of the Company's forecasted budget for tree trimming and other transmission and distribution operation and maintenance expense, there is a dispute among the parties regarding the level of expense attributable to contractor tree trimming. Orange and Rockland claims justification for an allowance of $5.88 million. According to the Company, it is justified in allocating an additional one million dollars to contractor tree trimming expense for the year ending June 30, 2008, to reflect a significant expansion of "danger tree" programs on both its distribution and transmission systems. These expansions will result in an increase of $500,000 annually for each program.[35] Moreover, additional costs of $150,000 will be required to address new regulations.

Staff proposes to reduce the Company's request by $1.335 million, to $4.752 million.[36] Staff asserts that the Company has not met its burden of proof on this issue, because

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[33] Cases 90-E-0647, et al., Rochester Gas and Electric Corporation–Rates, Opinion No. 91-13 (issued June 25, 1991), p. 20; Case 28656, New Rochelle Water Company–Rates, Opinion No. 84-21 (issued August 16, 1984), pp. 9-10; Case 89-G-179, National Fuel Gas Distribution Corporation–Rates, Opinion No. 90-20 (issued July 19, 1990), pp. 16-18.

[34] Staff Initial Brief at 17-18.

[35] Staff Initial Brief at 14, Tr. P-622.

[36] Staff Initial Brief at 13, Tr. P-898.

it cannot accurately predict its actual danger tree work volume going forward. Ramapo supports the Staff position. It asserts that Orange and Rockland has spent less than it requested for tree trimming throughout the past four years.[37]

In response, the Company acknowledges that it cannot predict with specificity the exact number of danger trees that will need to be removed in the future. However, it argues that the inability to forecast with certainty is beside the point. Instead, the Company notes its "deep-seated belief that its proposed tree trimming expenditures are critical to improving service reliability."[38] The Company asserts that it will accept a one-way true up of these expenditures, such that the Company would defer for customer benefit the amount of any shortfall between budgeted amounts and actual expenditures.

We will accept both the Company's budgeted amount for tree trimming expense and its offer to defer shortfalls for customer benefit. In this way, we can best assure that critical reliability programs are fully funded and carried out, while at the same time, ensuring that ratepayers do not overpay for expenses that are not actually incurred. Staff's adjustment is therefore denied. Staff should continue to audit the Company's tree trimming program and the Company's expenditures.

Workers Compensation Expense

Staff proposes an adjustment to the Company's forecast for workers compensation costs, in order to set a level based on the annual three-year average of workers compensation expense for 2004-06.[39] However, Staff proposes to use reserve accounting, so that Orange and Rockland's actual expenditures are fully funded by ratepayers. It appears that the Company accepts this proposed accounting treatment. In any event, we

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37 Ramapo Initial Brief at 4-5

38 Orange and Rockland Reply Brief at 5.

39 Staff Initial Brief at 12-13.

will adopt Staff's estimate as reasonable and the use of reserve accounting to protect the both the Company's and ratepayers' interests.

Pension and OPEB Expense

Staff proposes to increase the expense allowance for pension and OPEB expense by $15.255 million to lower the Company's rate of return to Staff's recommended 8.95% level. Staff asserts that this adjustment is preferable to a reduction in base rates, because it addresses the concern we expressed when we instituted this proceeding regarding Orange and Rockland's growing deferral balances for pension and OPEB expense.

Orange and Rockland notes on brief that it and Staff agree that the current expense allowance contained in rates in inadequate. It proposes to address the issue either by increasing rates or implementing a surcharge. It characterizes the Staff position as a refusal to confront the issue of the need to increase the base rate allowance.

We adopt the Staff recommendation as the most reasonable means of addressing the dual concerns in this case of company over-earnings, on the one hand, and an understated OPEB and pension expense allowance, on the other hand. We have revised the dollar figure recommended by Staff to reflect our update to the ROE and our decisions regarding other revenue requirement matters reflected in this order. The result is an increase to the OPEB and pension expense allowance included in base rates of $13,084,000. The calculations supporting this expense allowance, which essentially falls out from our other determinations herein, are set forth in the Appendix to this order.

RATE BASE

The record reflects agreement among the parties regarding rate base issues, leaving no disputed matters for us to decide here. Orange and Rockland proposed several additions to its transmission and distribution plant in this case. Staff asserts that it has reviewed the proposals and finds them warranted to improve and upgrade Orange and Rockland's system. Staff states that the upgrades will enhance Orange and Rockland's ability to satisfy load growth and improve the electric system's overall reliability.

REVENUE

Joint Operating Rents

Because Orange and Rockland, through subsidiaries, conducts operations in New Jersey and Pennsylvania, it must allocate shared costs and the use of common facilities among itself and its affiliates. Reimbursement for common costs and payment for use of joint facilities takes the form of joint use rents received by Orange and Rockland from its affiliates. The only outstanding dispute between Staff and Orange and Rockland concerns the recovery of state taxes in the forecast for joint use rents. Both Staff and the Company agree that the agreement for joint use rents should be structured so that taxes to New York, New Jersey, and Pennsylvania are properly allocated to the customers in those jurisdictions.[40] Orange and Rockland proposes to follow what it calls a traditional approach to the recovery of state taxes, and it rejects Staff's proposed modification, which would require that the forecast of joint use rents billed to affiliates provide for recovery of state income taxes. As Staff points out, a modification is necessary to reflect the change in New York State tax structure, whereby the gross receipts tax was eliminated and replaced with an income-based tax. Therefore, we will accept the Staff adjustment as

[40] Orange and Rockland Initial Brief at 13-14; Staff Reply Brief at 5-6.

necessary to ensure that the costs related to jointly used plant are recovered from the appropriate group of ratepayers.

ACCOUNTING MATTERS

Netting of Deferred Credits and Debits

Both Orange and Rockland and Staff note that the Company is maintaining deferral balances in a variety of categories of both credits and charges. Orange and Rockland proposes to use all available credits to offset deferred charges to the extent practical.[41] According to the Company, there is no compelling rationale for eliminating only a percentage of certain deferred charges if credits are available to cover them. Staff, on the other hand, proposed using only a portion of available credits. Staff's stated rationale is to provide some limited flexibility to mitigate rates when dealing with remaining deferred charges in the future.[42]

Neither proposal is unreasonable. In this instance, we will adopt the Company's position. The current situation, where rates are not changing, presents an ideal opportunity to "clean up" the Company's outstanding deferral balances without any adverse ratepayer impact.

Accounting Deferrals

1. Storm Reserve

In general, Staff and the Company have, through the process of discovery and litigation, reconciled virtually all the initial disputes relating to the treatment of certain deferred expenses. To the extent there remains a dispute regarding the appropriate amount of the storm reserve, we will adopt Staff's proposal to fund the storm reserve at the level of $1 million. Staff's proposal properly adjusts for the single year forecast otherwise being used here, whereas the Company's

[41] See Tr. P-660.

[42] Staff Initial Brief at 34.

forecast was based on a two-year budget. In any event, actual storm costs will continue to be reconciled, such that the Company will be made whole for its reasonably incurred storm-related costs.

2. Property Tax Benefits

The Company proposes that we grant advance authorization to the Company to retain 14% of any benefits achieved through challenges to property tax assessments in the future.[43] It notes that such an 86% customer/14% shareholder allocation has been approved by the Commission in the past. However, the Company fails to note that such Commission approval in the past has been given in the context of approving consensual joint proposals establishing rate plans for a defined term of years. In such cases, the plan attempts to anticipate the proper balance to be struck between shareholders and ratepayers over the term of the plan. In this case, where the rates we order today will not extend for any particular defined term, there is no need or basis for us to anticipate future property tax disputes or their resolution. Rather, we will address any property tax benefits only when they occur and are presented to us by Orange and Rockland.

LOW INCOME PROGRAM

Initially, there was a dispute among the parties as to the continuation and scope of the Company’s program to provide a credit to low-income heating customers. Through the litigation process, the parties have agreed to an expansion of the program so that low-income heating customers receive a credit of $10 rather than $5 per month and so that non-heating HEAP-eligible customers receive a $5 bill credit every month rather than just during the months of May through September. This expansion of

[43] Orange and Rockland Initial Brief at 48.

the program results in a total annual cost of $430,000. The parties agree that such a program can appropriately be funded through the use of available credits, at least through the upcoming rate year. We will therefore adopt the proposal for the expansion of the program, to be funded by these credits, which is supported by Orange and Rockland, Staff, and Ramapo.

INCENTIVE PROGRAMS

Customer Service Performance Incentive

Staff and the Company are in accord that the Company will continue to operate under a customer service performance incentive program, under which the Company is subject to negative revenue adjustment if it fails to maintain targeted levels of customer service. The parties are generally in accord as to the appropriate targets for measuring such performance, with the exception of two changes proposed by Orange and Rockland. The primary dispute is whether the amount at risk under the program should be increased.

Orange and Rockland proposes two modifications of the survey portion of its customer service incentive mechanism. First, it proposes that it not be judged by customers' responses that reflect their "price opinion" on the surveys. According to Orange and Rockland, the Company is judged on the basis of "price opinions" that reflect customers' views of both gas and electric prices. Particularly in the case of gas prices, the Company has little control over the cost, yet is affected negatively on the surveys if such costs go up. Therefore, the Company proposes to eliminate the "price opinion" factor from its survey target.

Second, the Company proposes that the survey portion of its incentive mechanism have tiered incentives similar to those relating to the complaint rate portion of the program. At present, there is a single target such that the incentive mechanism works on an “all or nothing” basis. Orange and Rockland notes its willingness to work collaboratively with Staff and other interested parties to establish the tier levels for the survey portion of its incentive mechanism.

Staff responds by noting that price remains an important factor in customer satisfaction, as it was when the survey target was implemented a year ago. Staff argues that Orange and Rockland has not provided sufficient reason or rationale to modify the survey mechanism. On the contrary, we find Orange and Rockland’s suggestions to be reasonable, based on the experience it has now acquired through use of the survey mechanism for one year. We will accept its proposal to eliminate price opinion from the incentive target, although the question should continue to be part of the survey. With the elimination of the price opinion of the target, the amount by which the Company is at risk should be re-apportioned among the other factors included in the customer satisfaction survey. Moreover, we will direct Orange and Rockland to work with Staff and other parties, as proposed, to develop tiered amounts at risk for the survey mechanism. If the parties agree, their consensus proposal can be submitted in compliance with this order. If they are unable to agree, they can submit the dispute to us for a decision.

Staff has proposed to increase the total amount at risk under the customer service incentive program to $1.1 million from the current level of $450,000 (measured in terms of its equivalence of basis points). The Company opposes the Staff proposal. It notes that the Company has not shown any deterioration in service quality based on customer complaints and that its recent customer service performance has been satisfactory. The Company asserts that its record of performance weighs in favor of maintaining its performance incentive at the current level.

We will adopt the Staff proposal to increase the level of revenue at risk to Orange and Rockland under the customer service performance incentive. Such an increase will bring Orange and Rockland's performance incentive more in line with those of other utilities in the state, which all operate under similar performance incentives with significantly greater amounts at risk. We commend Orange and Rockland on its good service to date. We reject the Company's view that increasing the amounts at risk is somehow a punishment that is meted out to companies with poor service. On the contrary, our goal, of course, is to ensure that companies achieve their customer service goals and that the incentive mechanisms not result in revenue adjustments. Here, an increase of the amount at risk is necessary to continue to make the incentive program meaningful.

Service Reliability Performance Incentive

Staff and the Company agree that Orange and Rockland should continue to operate pursuant to a service reliability performance incentive program. They further agree to the changes in the performance targets, as proposed initially by the Company, to reduce the target frequency of service interruption from 1.70 times to 1.36 times per year and to increase the existing target of the duration of a customer's interruption from 1.54 hours to 1.70 hours.

The parties disagree as to the consequences of the Company failing or exceeding the proposed targets, however. Although Orange and Rockland initially proposed a positive incentive award for meeting and exceeding the targets, it appears to have abandoned that proposal on brief. Staff proposes the amount by which the Company is at risk for a negative revenue adjustment be increased from four basis points per target to ten basis points per target, for a possible total of 20 basis points for the failure of both service reliability targets. Orange and Rockland opposes the Staff request.

We will accept the Staff proposal. We agree that increasing the amounts at risk begins to move Orange and Rockland in line with other New York State utilities operating under similar incentive mechanisms. Given the small amounts at risk for Orange and Rockland, we would be open to consideration of further increasing the amounts by which the Company is at risk in the future. Again, as is the case with the customer service performance mechanism, we do not expect companies to fail the incentive targets, and we are not increasing the amounts at risk out of some fear or expectation of a deterioration in Orange and Rockland’s service reliability. Rather, the amounts at risk are increased simply to make the mechanism a meaningful one.

Our expectations of the reliability of Orange and Rockland’s service reflect our inclusion in base rates of requested expense increases to fund system improvement programs such as the proposed comprehensive pole inspection and treatment program, the addition of overhead and underground linemen, and the emergency management and preparedness program, as well as the cost for tree trimming, stray voltage testing and the increase in the overall complement of employees to ensure appropriate knowledge transfer. We are accepting, as well, Orange and Rockland’s proposed additions to rate base, some of which will improve and upgrade existing transmission and distribution equipment. Our allowance for all of these capital improvements and expenses should ensure that Orange and Rockland will meet the reliability targets for the outage frequency and duration measures.

ENERGY EFFICIENCY PROGRAM

Pursuant to the ruling of the ALJ in this proceeding, issues relating to the design of an energy efficiency program and a revenue decoupling mechanism are not before us at this time. Rather, the parties are considering those issues in a second phase of this proceeding, in a collaborative and paper process. However, Orange and Rockland seeks clarification in its brief that the Company is authorized to proceed in the immediate term to use some unexpended funds attributable to Demand Side Management and low income aggregation to fund a study and to hire staff in contemplation of implementing a future energy efficiency program, at a cost of $150,000-$200,000 for the study and $140,000-$160,000 for the staff.[44] The record reflects the agreement of the parties to the proposal. Orange and Rockland should proceed to take these steps now, in anticipation of the program that will come before us at a later date.

STRAY VOLTAGE PETITION

There is no issue to be resolved in this case regarding Orange and Rockland's expense allowance to perform necessary inspections for stray voltage as required by our order in Case 04-M-0159.[45] The parties are in agreement as to the appropriate budget allowance to be included in rates. However, Orange and Rockland uses this forum to urge our action on its pending petition in that other proceeding to be relieved of the obligation to perform stray voltage testing as often and as thoroughly as is currently required. We are continuing to monitor all utilities' inspections and actions to address this critical problem in our generic proceeding. There is no record developed in this case on which we could or should make any change in Orange and Rockland's compliance requirements. Rather, we will continue our investigations in Case 04-M-0159

[44] Tr. 536, 563-64.

[45] Case 04-M-0159, Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems, Order Instituting Safety Standards (issued January 5, 2005).

and consider Orange and Rockland's petition in that context, rather than here.

DISPOSITION OF OVERPAYMENTS FROM TEMPORARY RATE PERIOD

The parties are in accord that whatever ROE we determine for Orange and Rockland's permanent rates in this proceeding should be used as well as a guide to the proper level of earnings for the time that rates have been temporary, since March 1, 2007. There remain disputed issues regarding the amount of ratepayer overpayments that should be allocated for customer benefit as well as the form such customer benefits should take.

Staff, supported by CPB, proposes that all earnings in excess of the ROE established by this Order be applied against the deferral balance maintained by the Company for pension and OPEB expense. According to Staff, any and all earnings above the allowed ROE should be viewed as above and beyond the level required to adequately compensate the Company and should be subject to disposition by the Commission. Staff asserts that, since earnings sharing under Orange and Rockland's prior rate plan ended on June 30, 2006, the Company has received an undue windfall. According to Staff, the institution of temporary rates was ordered to protect customers from the continuation of this circumstance.[46] CPB agrees, asserting that all earnings exceeding the allowed ROE should be used for the benefit of ratepayers, as an offset to the deferred pension and OPEB expense.[47]

Orange and Rockland, in contrast, asserts that what it calls the "bare bones" cost of equity should not be a "cap" on the Company's earnings during the temporary rate period.[48]

[46] Staff Initial Brief at 42.

[47] CPB Initial Brief at 3.

[48] Orange and Rockland Initial Brief at 42.

Instead, Orange and Rockland argues that it should be allowed to retain at least a portion of the productivity savings it generated during the temporary rate period. According to Orange and Rockland, sharing of some earnings during the temporary rate period would be consistent with incentive ratemaking and would constitute fair treatment of Orange and Rockland, which has continued to operate its business efficiently during the temporary rate period.[49] Moreover, Orange and Rockland asserts that operating under a temporary rate regime has exposed the Company to undue and unwarranted risks. In particular, the Company has not been protected from retroactive ratemaking during this period, because, Orange and Rockland asserts, the Commission may review retroactively the Company's business decisions during the temporary rate period.[50]

Based on these considerations, the Company proposes that a deadband of 100 basis points be added to the "bare bones" return on equity before any earnings are shared with ratepayers. Beyond the 100 points deadband, the Company further proposes to share 50/50 the earnings up to a second 100 basis points, above which 100% of any earned equity return would be allocated 100% to ratepayers. The Company asserts that this result would be consistent with the testimony of Company witness Rasmussen that the minimum earnings sharing threshold should be 12.75% of common equity.

The Supervisor of the Town of Ramapo characterizes Orange and Rockland's position as "contemptible."[51] Ramapo urges us to invoke PSL §66(20), which provides, in part, that the Commission "shall have the power to provide for the refund of any revenues received by any gas or electric corporation which cause the corporation to have revenues in the aggregate in

[49] Id. at 42.

[50] Orange and Rockland Initial Brief at 42-43.

[51] Ramapo Initial Brief at 6.

excess of its authorized rate of return for a period of twelve months."[52] Ramapo asserts that, pursuant to §66(20), the Company should disgorge and refund all earnings above the 8.95% ROE recommended in Staff's testimony that Orange and Rockland earned since July 1, 2006, when the earnings sharing provision under the former rate plan expired. Ramapo thus disagrees with the proposal to compute refunds only for the period beginning March 1, 2007, when temporary rates went into effect.

Ramapo further opposes the Staff and CPB proposal that the extra earnings be used to offset pension and OPEB expense. Instead, Ramapo argues that Orange and Rockland should pick up the cost of reducing the pension and OPEB expenses that it unreasonably deferred, and the extra earnings should be refunded directly to ratepayers. Ramapo asserts that this result is appropriate because the Company deferred the pension and OPEB expenses all the while it was making extra money.[53]

We adopt the Staff and CPB proposal for the disposition of amounts due and owing to ratepayers for the temporary rate period. That is, the Company's earnings in excess of 9.1% ROE will be applied to the outstanding deferral balances for pensions and OPEBs. In making this disposition, we reject entirely the distinction the Company attempts to create between some "bare bones" ROE and some other, allegedly "fairer" ROE at a higher level. The Company's own expert testimony makes clear that an appropriate ROE is, by definition, the sum total of earnings to which the shareholders are entitled. Having properly analyzed and set the correct allowed return here, we have no basis for awarding extra earnings to the Company's shareholders.

What Orange and Rockland characterizes as the "normal" situation of earnings sharing is indeed a common hallmark of

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[52] Id.

[53] Id.

incentive rate plans. Typically, such provisions, ordinarily arrived at through settlements among Staff, the Company and Intervenors, provide protection for ratepayers and shareholders who might otherwise be disadvantaged under the multi-year terms for which such plans are set. Such ratemaking devices are not necessary or appropriate in cases such as this one, where we are not setting rates for a defined, multi-year term.[54]

Moreover, there is no need, at this juncture, to compensate Orange and Rockland for some hypothetical prospective risk for its operation under the temporary rate regime. Here, we are disposing of overearnings measured against the Company's actual earnings, which are known and quantified. There is no evidence that Orange and Rockland suffered any adverse financial consequence from operating under temporary rates. Even if it had, such consequences would already be reflected in its actual results.

We also note that the Company's characterization of the risk to which it was subjected by operating under temporary rates is exaggerated. We have the ability to examine and disallow costs that are not prudently incurred by the Company at all times, whether the Company is operating under temporary or permanent rates. We also have the authority to institute proceedings and conduct investigations into the Company's practices and rates at any time. We defined the scope of our concern in instituting this proceeding when we noted the Company's retention of excess earnings at the same time that its balances for deferred recovery of costs for OPEB and pension expense were growing. This order demonstrates how closely we have adhered to that initially announced scope. Therefore, there is no basis for the Company's assertion that somehow every dime of its revenue was placed in jeopardy in this proceeding.

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[54] Indeed, Orange and Rockland has already filed a new rate case, 07-E-0949, for rates to take effect in July 2008.

Moreover, as noted, the Company has not asserted any actual adverse financial effects from its temporary rate status.

We reject the proposal for relief of the Town of Ramapo. Initially, we note that Ramapo's proposal to proceed under PSL §66(20) and to refund all earnings above an allowed return since June 30, 2006 has been made for the first time on brief. That statute was not referenced in CPB's complaint nor in our Order to Show Cause initiating this proceeding, and it was not the subject of testimony or hearings in this case. We did not choose to proceed under that section of the Public Service Law but instead instituted this proceeding pursuant to PSL §§ 66(5), 72, and 114 to examine the Company's rates prospectively. We made rates temporary during our examination in order to prevent unjust enrichment to shareholders or undue harm to ratepayers while we carried out our inquiry. We did not, however, give notice of our intent to reach back in time, prior to the institution of the proceeding. Under these circumstances, it would be inappropriate for us now to rely on PSL §66(20).

Moreover, Orange and Rockland was operating pursuant to the terms of our prior rate order which expressly provided for the expiration of earnings sharing prior to the expiration of the rate plan itself in October of 2006. Where we did not take action to modify our prior rate order, Orange and Rockland was entitled to rely upon its provisions without vulnerability to a later complaint for disgorgement under §66(20). Given the terms of that prior order, there has not been a twelve-month period of overearnings as contemplated by §66(20). Orange and Rockland has undoubtedly enjoyed some extra earnings from November 1, 2006 until this proceeding could be instituted and proper procedures followed to make rates temporary. Much of that delay was needed, however, to ensure the proper due process was afforded to all parties and that there was indeed cause to move forward to ameliorate the situation. Ramapo's request would effectively undo the procedural safeguards in which we have already invested considerable time and effort to ensure a fair outcome.

We further reject Ramapo's suggestion that OPEB and pension costs be the responsibility of shareholders rather than ratepayers. Such a result conflicts directly with our policy statement on pensions and OPEBs. There is no record in this proceeding that would justify such a radical departure from the ordinary cost responsibility.

PROPERTY TAX REFUNDS

As noted above, Orange and Rockland's petition for the disposition of property tax refunds from the Towns of Haverstraw and Orangetown, filed in Case 06-E-0547, was considered with this rate proceeding, Case 06-E-1433, for purposes of the evidentiary hearings and briefing of the issues. The Company's petition was included as an exhibit at the hearing.[55]

It appears that Staff and other parties accept the Company's description of the efforts expended to obtain reduced assessments and refunds of tax amounts already paid to the Towns, as well as the Company's accounting of the amount of the refunds allocable to Orange and Rockland's New York electric operations. The only issue in dispute is the difference in the parties' positions regarding the percentage that should be allocated for retention by Orange and Rockland as an incentive to pursue such tax reductions. It has been a longstanding policy of this Commission to award such incentive amounts in

[55] Exhibit 39, RAB-4.

property tax refund cases.[56] As our past precedents show, the Commission has generally awarded shareholders a percentage of the proceeds ranging from 10% to 25%. Staff advocates for 10%, while Orange and Rockland argues that it is entitled to retain 25%.

Orange and Rockland argues that its efforts produced benefits, not only in the form of refunds, but also in the reduced assessments that will continue forward. It refers to the agreement of the taxing authorities to use the Replacement Cost New Less Depreciation method in future assessments. Because of the prospective benefits, in which the Company will not share, Orange and Rockland argues that a balance should be struck by compensating the Company with a higher percentage of the refund amount.[57]

Staff responds that, while our new rate-setting here will capture the reduction in the tax assessment resulting from the Company's settlements, the Company has received the benefit of the reduced tax assessment from November 1, 2006 to February 28, 2007. In addition, Staff notes that the Company was largely expending its efforts to achieve these settlements during the term of the prior rate plan, which provided for the Company to share 10 percent of tax benefits. Therefore, Staff argues, allowing the Company to retain 10% in this case would be consistent with the expectations the Company should have had at

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[56] See, e.g., Case 04-M-0613, Central Hudson Gas & Electric Corporation – Tax Refund, Order Addressing State Tax Refund (issued December 20, 2004); Case 03-M-1148, Consolidated Edison Company of New York – Tax Refund, Order Addressing Federal Tax Refund (issued March 24, 2005); Case 88-G-180, National Fuel Gas Distribution Corporation–Rates, Opinion No. 89-22 (issued July 19, 1989), pp. 28-32; Case 98-M-061, Consolidated Edison Company of New York–Special Franchise Tax Benefits, Opinion No. 90-1 (issued January 2, 1990); Case 27879, Orange and Rockland Utilities, Inc., Order Requiring Flow-Through of Property Tax Refunds (issued April 28, 1981).

[57] Orange and Rockland's Initial Brief at 45-56.

the time it was pursuing the tax benefits.[58] Moreover, Staff notes that, under the last rate plan, the Company received the benefit of complete reconciliation between the property tax allowance in rates and actual payments for such taxes. This reduced level of risk regarding property taxes also counsels in favor of an incentive percentage at the lower end of range, according to Staff. Ramapo supports the Staff position.

Given the circumstances of this case, we believe it is appropriate to allow the Company to retain 10% of the tax refunds. We agree with Staff that the reduced assessments going forward do not provide a basis for increasing the standard percentage of a refund to be retained by the Company. Reduced assessments in the future are a common result of any tax assessment challenge. In addition, the Replacement Cost New Less Depreciation methodology is not new or extraordinary. Rather, as the Company's petition points out, it has become an accepted method for valuing utility property.[59] A retention of 10% of the benefit in this case is an ample award for the Company's efforts and an appropriate incentive to continue such activities.

The Commission orders:

1. Orange and Rockland Utilities, Inc.'s electric rates, currently in effect, will remain unchanged and become permanent as of the effective date of this Order. The Company need not file new tariff amendments. Rather, Staff will note on each affected tariff leaf currently on file that Case 06-E-1433 is closed regarding the temporary status of rates.

2. The allowance included in rates for the costs of pensions and other post-employment benefits incurred by the Company is increased as discussed herein.

[58] Tr. 925-26, Staff Initial Brief at 44.

[59] Exhibit 39, RAB-4, pp. 2-3.

3. Orange and Rockland Utilities, Inc.'s excess earnings since March 1, 2007, calculated consistent with this order, are hereby applied to customers' benefit by applying the amount of overearnings to the deferred balances of amounts due and owing to the Company for pension and other post-employment benefits expense, as discussed herein. The Company shall submit an accounting of the customer overpayments reflected by such excess earnings during the temporary rate period to the Director of Accounting, Finance & Economics within 60 days of the date of this order except as otherwise directed by the Secretary.

4. Orange and Rockland Utilities, Inc. shall report monthly, through June 2008, to the Director of Electricity, Gas and Water regarding the number of its linemen as discussed in this order.

5. Orange and Rockland Utilities, Inc. shall work with Staff and other interested parties to this proceeding to develop a tiered incentive for the survey portion of its customer service incentive program, consistent with the discussion in this order. The Company shall file this incentive proposal with the Commission Secretary within 60 days of the date of this order except as otherwise directed by the Secretary. In the event the parties are unable to reach consensus, the Company's filing will represent its own proposal, and other parties shall file comments and/or counter-proposals in response to the Company's filing in accordance with a schedule to be set by the Secretary.

6. Orange and Rockland Utilities, Inc. may retain 10% of the tax benefits received as a result of its settlements of litigation with the Towns of Orangetown and Haverstraw for shareholders. The remaining tax benefits attributable to ratepayers are included in the netting of regulatory credits and debits discussed herein.

7. Case 06-E-1433 is continued.

8. Case 06-E-1547 is closed.

By the Commission,

(SIGNED) JACLYN A. BRILLING
Secretary

Attachment: Appendix w/Schedules 1-9

Orange and Rockland Utilities, Inc.
Electric Service
Operating Income, Rate Base & Rate of Return
For the Twelve Months Ending June 30, 2008
(000's)

	Staff Rate Year Ending 06/30/08	Adj. No.	Commission Adjustments	Commission Rate Year Ending 06/30/08	Pension/OPEB Expense Allowance	Per Commission After Expense Allowance Increase
Operating Revenues						
Sales to Public	$425,108			$425,108		$425,108
Surcharge for Regulatory True-ups						
Sales for Resale	28,950			28,950		28,950
Other Revenues	7,532	1	14	7,546		7,546
Total Operating Revenues	461,590		14	461,604		461,604
Operating Expense						
Purchased Power Supply Expense	255,318			255,318		255,318
Deferred Purchased Power	(1,181)			(1,181)		(1,181)
Other O&M Expense	99,609	Sch.2	1,482	101,091	13,084	114,175
Operation & maintenance expense	353,746		1,482	355,228	13,084	368,312
Depreciation expense	23,757			23,757		23,757
Taxes other than income taxes	23,937			23,937		23,937
Gains from Disposition of Utility Plant						
Total Operating Expense	401,440		1,482	402,922	13,084	416,006
Operating income before income taxes	60,150		(1,468)	58,682	(13,084)	45,598
New York State income tax	3,191	Sch.4	(113)	3,078	(929)	2,149
Federal income tax	15,194	Sch.5	(516)	14,678	(4,254)	10,424
Utility operating Income	$41,765		($840)	$40,926	($7,901)	$33,025
Rate Base	$436,153	Sch.6	$518	$436,671		$436,671
Rate of Return	9.58%					7.56%
Weighted cost of debt and preferred stock	3.21%					3.23%
Weighted return on equity	6.37%					4.33%
Equity ratio	47.54%					47.54%
Return on equity	13.40%					9.10%

Orange and Rockland Utilities, Inc.
Electric Service
Operation & Maintenance Expense
For the Twelve Months Ending June 30, 2008
(000's)

	Staff Rate Year Ending 06/30/08	Sch.8 Adj. No.	Commission Adjustments	Commission Rate Year Ending 06/30/08
Purchased Power Supply Expense	$255,318			$255,318
Deferred Purchansed Power	(1,181)			(1,181)
Subtotal Purchased Power Costs	$254,137			$254,137
Other O&M Costs				
Direct Labor (Excl. Shared Services)	40,653	2	319	$40,972
Shared Services	9,320			9,320
Employee and Other Insurance Costs	8,141			8,141
Regulatory Costs and Amortizations:				
R&D Deferrals				
R&D - Current Spending				
System Benefit Charge	4,672			4,672
Stray Voltage Program				
Stray Voltage Prog. - Current Spending	1,686			1,686
Storm Reserve				
Deferred 1st Installed Transformers				
Oil Supplier Refunds				
DSM Overrecoveries				
Pension and OPEBs	6,643			6,643
Uncollectible Accounts	2,318			2,318
MGP Sites & West Nyack Environmental Co				
Tree Trimming / T&D O&M	13,520	3	1,163	14,683
- Storm Charge				
- Pole Inspection	612			612
-Overhead Contractor Circuit Reliability	431			431
- Amortization of Deferred Transformer Crec				
- 1st Installation of Transformers - Ongoing (	(862)			(862)
Regulatory Commission Expenses	1,398			1,398
Other O&M Costs:				
Advertising	503			503
Information Technology Solutions	2,314			2,314
Legal & Other Professional services	420			420
Rents	1,047			1,047
Materials and Supplies	1,068			1,068
Corporate Fiscal	1,034			1,034
Other O&M	4,691			4,691
Subtotal - Other O&M Costs	$99,609		$1,482	$101,091
Total O & M Expense	$353,746		$1,482	$355,228

Orange and Rockland Utilities, Inc.
Electric Service
Taxes other than income taxes
For the Twelve Months Ending June 30, 2008
(000's)

	Staff Rate Year Ending 06/30/08	Adj. No.	Commission Adjustments	Commission Rate Year Ending 06/30/08	Effect of Revenue Increase	Per Commission After Increase
Property Taxes						
County and Town	$4,760			$4,760		$4,760
Village	1,226			1,226		1,226
School	10,708			10,708		10,708
Subtotal	16,694			16,694		16,694
Property Tax True Up 02-G-1553						
Amort Def. Over Recoveries						
Amort of Refunds						
Total Property Taxes	16,694			16,694		16,694
Payroll Taxes	2,590			2,590		2,590
Revenue Taxes - Sales Revenue	4,653			4,653		4,653
-Regulatory Surcharge						
All Other						
Total Taxes Other Than Income Taxes	$23,937			$23,937		$23,937

Orange and Rockland Utilities, Inc.
Electric Service
New York State Income Tax
For the Twelve Months Ending June 30, 2008
(000's)

	Staff Rate Year Ending 06/30/08	Adj. No.	Commission Adjustments	Commission Rate Year Ending 06/30/08	Pension/OPEB Expense Allowance	Per Commission After Expense Allowance Increase
Operating Income before income taxes	$60,150	Sch.1	($1,468)	$58,682	($13,084)	$45,598
Less: Interest Expense	13,813		118	13,931		13,931
	46,337		(1,586)	44,751	(13,084)	31,667
Permanent Differences						
Add: Additional Taxable Income & Unallowable Deductions:						
Unallowable Business Expense	51			51		51
Non Taxable Income, Unallowable deductions						
Total	51			51		51
Deduct: Non Taxable Income & Additional Allowable Deductions:						
Medicare Reimbursement	(1,449)			(1,449)		(1,449)
Pre Tax Income	44,939		(1,586)	43,353	(13,084)	30,269
Normalized Items:						
Add: Additional Taxable Income & Unallowable Deductions:						
Book depreciation-Charge to Expense	23,757			23,757		23,757
Book depreciation-Charge to Clearing Acct.	1,632			1,632		1,632
Capitalized Interest	1,289			1,289		1,289
General Liability Insurance						
Workmen's Compensation						
Auto Liability Insurance						
Medicare Reimbursement						
Post Employeement Benefits Cap/Exp (FASB 106)	2,038			2,038	4,146	6,184
Reserve for Medical Insurance						
Contribution in Aid of Construction	1,375			1,375		1,375
Contribution in Aid of Constr.- Refundable	(23)			(23)		(23)
Increase in Deferred Fuel Cost	(1,181)			(1,181)		(1,181)
Environmental Reserve	112			112		112
Supplemental Pension-Non Qualified	951			951		951
Revenue Subject to Refund						
Unallowable Book Pension Expense	1,895			1,895	8,938	10,833
SIT Refund Interest						
Property Tax Refund - Net 461H						
Total Normalized Additions	31,845			31,845	13,084	44,929
Deduct: Non Taxable Income and Additional Allowable Deduction:						
NYS Tax Depreciation - Existing Book Rates	39,160			39,160		39,160
Removal costs	781			781		781
Lien Date Property Tax Deduction	103			103		103
AFUDC						
Loss on Disposition of Property	844			844		844
R&D Expense Debited to Reserve						
OPEB Funding	7,147			7,147		7,147
Competitive Enhancement Funds						
MTA Tax Deferred						
Environmental Cost - Qer Expend Sect. 198	5,270			5,270		5,270
Storm Damage Deferred on Books						
Pension Funding	18,404			18,404		18,404
Conservation/DSM/LCAPS						
Amortization - CIAC Pyramid Mall						
Stray Voltage						
Change of Accounting - Sec 263A Adj						
Software Cost - Developed CIMS-plus - Walker	2,029			2,029		2,029
Total Normalized Deductions	73,738			73,738		73,738
Total Adjustment to Book Income	(41,893)			(41,893)	13,084	(28,809)
Taxable Income	$3,046		($1,586)	$1,460		$1,460
Current NYS Income Tax Payable @ 7.1%	$216		($113)	$104		$104
Deferred NYS Income tax	2,974			2,974	(929)	2,045
Total SIT (excl MTA)	$3,191		($113)	$3,078	($929)	$2,149
MTA Tax @ 1.53%						
Deferred State MTA Taxes @ 1.53%						
NYS Income Tax Per Book	$3,191		($113)	$3,078	($929)	$2,149

Orange and Rockland Utilities, Inc.
Electric Service
Federal Income Tax
For the Twelve Months Ending June 30, 2008
(000's)

	Staff Rate Year Ending 06/30/08	Adj. No.	Commission Adjustments	Commission Rate Year Ending 06/30/08	Pension/OPEB Expense Allowance	Per Commission After Expense Allowance Increase
Operating Income before income taxes	$60,150	Sch.1	($1,468)	$58,682	($13,084)	$45,598
Less: NYS income tax expense	3,191	Sch. 4	(113)	3,078	(929)	2,149
Interest Expense	13,813		118	13,931		13,931
Book Income Before FIT	43,146		(1,473)	41,673	(12,155)	29,518
Flow Through Items:						
Add: Additional Taxable Income and Unallowable Deductions:						
Book depreciation - Charged to expense	23,757			23,757		23,757
Book depreciation - Charged to Clearing Accts	1,632			1,632		1,632
Capitalized interest	1,289			1,289		1,289
Unallowable Business Expense	51			51		51
Non Taxable Income, Unallowable deductions						
Total	26,729			26,729		26,729
Deduct: Non Taxable Income and Additional Deductions:						
Statutory depreciation	21,878			21,878		21,878
Removal costs	781			781		781
Medicare Reimbursement	1,449			1,449		1,449
Lien Date Property Tax Deduction	103			103		103
AFUDC						
Loss on Disposition of Property	844			844		844
Total	25,055			25,055		25,055
Pre Tax Income	44,820		(1,473)	43,347	(12,155)	31,192
Normalized Items:						
Add: Additional Taxable Income and Unallowable Deductions:						
Increase in Deferred Fuel Cost	(1,181)			(1,181)		(1,181)
Medicare Reimbursement						
Amort. Of Bond Redemption Cost	154			154		154
Post Employeement Benefits Expense	2,038			2,038	4,146	6,184
Reserve on Medical Insurance						
Deferred State Income Tax Non Deductible	2,974	Sch.4		2,974	(929)	2,045
Contribution in Aid of Construction	1,375			1,375		1,375
Contribution in Aid of Constr.- Refundable	(23)			(23)		(23)
Environmental Reserve	112			112		112
Book Amort. Computer Software	623			623		623
Revenue Subject to refund						
Unallowable Book Pension Expense	1,895			1,895	8,938	10,833
Supplemental Pension - Nonqualified						
Excess Book Over Tax Depr. - B.H.	(18)			(18)		(18)
SIT Refund Interest						
Property Tax Refund						
Total Normalized Addtions	7,949			7,949	12,155	20,104
Deduct: Non Taxable Income and Additional Deductions:						
Tax Depreciation (Norm) - ADR/ACRS/MACRS	8,116			8,116		8,116
Pension Funding	18,404			18,404		18,404
OPEB Funding	7,147			7,147		7,147
R&D Expense Debited to Reserve						
Competitive Enhancement Funds						
Excess Tax Depr. Over Vehicle Lease Exp.	(405)			(405)		(405)
MTA Tax Deferred						
Environmental Cost - Qer Expend Sect. 198	5,270			5,270		5,270
Conservation/DSM/LCAPS						
Amortization - CIAC Pyramid Mall						
Stray Voltage						
Storm Damage Deferred on Books						
Software Cost - Developed CIMS-plus - Walke	2,029			2,029		2,029
Change of Accounting - Sec 263A Adj						
Total Normalized Deductions	40,561			40,561		40,561
Total adjustments to book income	($32,612)			($32,612)	$12,155	($20,457)
Federal taxable income	$12,209		($1,473)	$10,735		$10,735
Current Federal income tax expense (35%)	$4,273		($516)	$3,757		$3,757
Deferred Federal income tax expense	11,414			11,414	(4,254)	7,160
Amort. Of Deferred FIT - Sect. 263A	(493)			(493)		(493)
Total Current Period FIT	15,194		(516)	14,678	(4,254)	10,424
Prior Years' (Over)/Under Accrual						
Total Federal income tax expense	$15,194		($516)	$14,678	($4,254)	$10,424

Orange and Rockland Utilities, Inc.
Electric Service
Rate Base
For the Twelve Months Ending June 30, 2008
(000's)

	Staff Rate Year Ending 06/30/08	Sch.8 Adj. No.	Commission Adjustments	Commission Rate Year Ending 06/30/08
Utility Plant:				
Plant in Service	$717,736			$717,736
Plant Held for Future Use	3,786			3,786
Common Plant	98,373			98,373
CWIP not Taking Interest	8,046			8,046
Total Utility Plant	827,941			827,941
Utility Plant Reserves:				
Accum. Prov Depr. (Inc. Future Use Plant)	(239,499)			(239,499)
Accum. Prov Depr. Of Common Plant	(51,116)			(51,116)
Total Utility Plant Reserves	(290,615)			(290,615)
Net Plant	537,326			537,326
Working Capital Requirements:				
O&M Expenditures	12,269	Sch.7	185	12,454
Materials & Supplies	4,029			4,029
Prepayments	4,806			4,806
Subtotal	21,104		185	21,289
Regulatory Assets / (Liabilities) (net of FIT)				
Deferred R&D Expenditures	644			644
Deferred Purchased Power	(7,164)	7a)	6,494	(670)
Deferred M.T.A Surtax	(236)			(236)
Deferred Low Income Program	(139)	7b)	(140)	(279)
Deferred Storm Reserve Expenditures				
Deferred Stray Voltage Expenditures	1,325	7c)	(1,325)	
Deferred Environ. Expenditures (West Nyack)	6,732	7d)	(6,732)	
Deferred DSM Recoveries	(600)			(600)
Deferred Oil Supplier Refunds				
Deferred Performance Penalties				
Deferred Gain on Sale of Wurtsbury Property				
Deferred Property Tax True Up				
Deferred Property Tax Refunds	(2,176)	7e)	2,036	(140)
Deferred 1st Installation costs Transformers				
Accrued Pension Liability - Rate Base Imputat	(6,403)			(6,403)
Customer Advances for Construction	(161)			(161)
Subtotal	(8,178)		333	(7,845)
Accum. Deferred Income Taxes				
Accum. Deferred FIT - ACRS/ADR	(72,420)			(72,420)
Accum. Deferred FIT - 263(A)	(13,489)			(13,489)
Accum. Deferred SIT	(4,444)			(4,444)
SIT Benefit - Pre 2000	379			379
Accum. Deferred MTA	206			206
Accum. Deferred Invest. Tax Credits	(1,689)			(1,689)
Subtotal	(91,457)			(91,457)
EB-Cap Adjustment	(22,642)			(22,642)
Total Rate Base	$436,153		$518	$436,671

Orange and Rockland Utilities, Inc.
Electric Service
Working Capital Allowance
For the Twelve Months Ending June 30, 2008
(000's)

	Staff Rate Year Ending 06/30/08	Sch.8 Adj. No.	Commission Adjustments	Staff Commission Rate Year Ending 06/30/08
Cash Working Capital				
Operations & Maintenance Expense	$353,746	Sch.2	$1,482	$355,228
Less:				
Purchased power expense	255,318			255,318
Uncollectibles	2,318			2,318
Regulatory Items (Deferred Charges)				
Deferred Purchased Power	(1,181)			(1,181)
R&D Amortization				
Stray Voltage Amortization				
Storm Reserve Amortization				
Environmental Remediation				
MGP Amortization Deferrals				
West Nyack Amortization				
Regulatory Items (Deferred Credits)				
Medicare Part D				
1st Installs - Transformers	(862)			(862)
Oil Supply refund				
DSM Overrecoveries				
	255,593			255,593
Net	98,153		1,482	99,635
Cash Working Capital @ 1/8	$12,269	6	$185	$12,454

Orange and Rockland Utilities, Inc.
Electric Service
Explanation of Adjustments
For the Twelve Months Ending June 30, 2008
(000's)

Appendix
Schedule 8

Adj. No.	Explanation		Amount
	Other Operating Revenues		
1	To reflect Commission's cost of capital and staff's methodology to forecast joint use rents		$14
	Operation and Maintenance Expense		
	Direct Labor		
2	To reflect company's full request for its linemen attrition program		$319
	Tree trimming and other T&D Expenses		
3	To reflect company's danger tree request level and additional compliance costs		$1,163
	State Income Taxes - Schedule 4		
4	SIT adjustment per schedule 4	tracking	($113)
	Federal Income Taxes - Schedule 5		
5	FIT adjustment per schedule 5	tracking	($516)
	Rate Base - Schedule 6		
6	To reflect additional cash working capital related to Commission's operating expense adjustments	tracking	$185
7	To reflect Commission's netting all available credits against deferred costs:		
	a) Deferred purchased power	$6,494	
	b) Deferred low income program	(140)	
	c) Deferred stray voltage expenditures	(1,325)	
	d) Deferred environmental expenditures	(6,732)	
	e) Deferred property tax refund	2,036	
			$333

Case 06-E-1433

Appendix
Schedule 9

Orange and Rockland Utilities, Inc.
Electric Service
Netting of Certain Available Deferred Credits
Against Certain Deferred Costs
For the Twelve Months Ending June 30, 2008
(000's)

Available Credits	Account	Balance	Netting Proposal	Balance After Netting	**Storm Reserve**
SIT Benefits - Pre 2000	229115	$6,973,000	($6,973,000)	$0	
SIT Benefits - Rate Changes	254700	629,700	(629,700)	0	
Deferred 1st Installation Costs - Tran	254328	1,695,326	(1,695,326)	0	
Oil Supplier Refunds	253151/064	576,921	(576,921)	0	
Gain - Sale of Wurtsboro Property	254385	94,068	(94,068)	0	
Performance Adjustment - 2001	229185	97,464	(97,464)	0	
Performance Adjustment - 2004	229190	115,000	(115,000)	0	
Performance Adjustment - 2005	229193	130,000	(130,000)	0	
Performance Adjustment - 2006	229101	246,078	(246,078)	0	
Property Tax True - up	254439/182439	5,278,593	(5,278,593)	0	
Property Tax Refunds - Ramapo	254530	612,609	(612,609)	0	
Property Tax Refunds - Clarkstown	254096	847,574	(847,574)	0	
Property Tax Refunds - Orangetown	254083	126,900	(126,900)	0	**For**
Property Tax Refunds - Haverstraw (	254084	2,004,368	(1,574,368)	430,000	**Low Income**
DSM Overrecoveries	254401	922,756	0	922,756	**DSM**
ECA Recoveries for Above Market N	253552	9,991,306	(9,991,306)	0	
Low Income Aggregation Program	254420	429,163	0	429,163	**DSM**
		30,770,826	(28,988,907)	1,781,919	
Identified Deferred Costs					
Pensions	182321	12,362,510	(2,652,451)	9,710,059	
OPEBs	182323	14,164,396	(3,047,689)	11,116,707	
OPEBs - Medicare Part D Tax Benef	254540	(3,335,665)	0	(3,335,665)	
Environmental Remediation - MGP D	182377	45,976,707			
- Accrual	242375	(34,005,063)			
- MGP Inter	182376	767,571			
- West Nyack (70.75%)	182374	153,157			
- West Nyack Ph	182372	235,428			
- Accrual West Nyack Pł	242376	(181,257)			
Environmental Remediation - Net Def. Costs		12,946,543	(12,946,543)	0	
Storm Reserve	182373	1,743,132			
Deferred Storm Costs	186044	2,198,923			
Total Storm Cost		3,942,055	(4,942,055)		($1,000,000)
Research and Development	188100	2,851,338	(2,851,338)	0	
Stray Voltage Program	182485	2,548,831	(2,548,831)	0	
		$45,480,008	($28,988,907)	$17,491,101	

H

Court of Appeal, Fifth District, California.
The PONDEROSA TELEPHONE CO., Petitioner,
v.
PUBLIC UTILITIES COMMISSION, Respondent;
Calaveras Telephone Company et al., Real Parties in Interest.

No. F061287.
July 5, 2011.

Background: Rural telephone companies petitioned to challenge Public Utilities Commission decisions which allocated the proceeds from the redemption of Rural Telephone Bank (RTB) stock to the telephone companies' ratepayers.

Holdings: The Court of Appeal, Levy, Acting P.J., held that:
(1) Class B shares purchased by telephone company were public utility assets that were owned by the company, and
(2) credit to ratepayers for proceeds of Class B patronage shares constituted an improper adjustment of previously approved rates.

Decision annulled.

West Headnotes

[1] Public Utilities 317A 146

317A Public Utilities
317AIII Public Service Commissions or Boards
317AIII(A) In General
317Ak145 Powers and Functions
317Ak146 k. Legislative and judicial powers and functions. Most Cited Cases

Public Utilities 317A 195

317A Public Utilities
317AIII Public Service Commissions or Boards
317AIII(C) Judicial Review or Intervention
317Ak188 Appeal from Orders of Commission
317Ak195 k. Presumptions in favor of order or findings of commission. Most Cited Cases

The Public Utilities Commission is not an ordinary administrative agency, but, rather is a constitutional body with broad legislative and judicial powers; accordingly, the Commission's decisions are presumed valid.

[2] Public Utilities 317A 194

317A Public Utilities
317AIII Public Service Commissions or Boards
317AIII(C) Judicial Review or Intervention
317Ak188 Appeal from Orders of Commission
317Ak194 k. Review and determination in general. Most Cited Cases

Where a Public Utilities Commission decision is challenged on the ground that it violates a constitutional right, the reviewing court must exercise independent judgment on the law and the facts and the Commission's findings or conclusions material to the constitutional question shall not be final. West's Ann.Cal.Pub.Util.Code § 1760.

[3] Public Utilities 317A 114

317A Public Utilities
317AII Regulation
317Ak114 k. Service and facilities. Most Cited Cases

By paying bills for service, utility customers do not acquire any interest, legal or equitable, in the property used for their convenience or in the funds of the company; rather, customers pay for service, not for the property used to render it.

[4] Telecommunications 372 942

372 Telecommunications
372III Telephones
372III(G) Rates and Charges
372k937 Determination of Rates

372k942 k. Rate base; property and revenues included. Most Cited Cases

Class B shares in Rural Telephone Bank (RTB) which were purchased by rural telephone company were public utility assets that were owned by the company such that ratepayers were not entitled to a par value redemption credit, other than portion of gain attributable to the shares in rate base; while company's investment in the RTB stock was funded though debt and thus included company's costs of capital, company was required to invest in the stock to provide utility service such that it was a public utility asset, and Public Utilities Commission required company to employ debt as part of its capital structure. West's Ann.Cal.Pub.Util.Code § 817.

See Cal. Jur. 3d, Public Utilities, §§ 54, 61, 74; Cal. Jur. 3d, Telegraphs and Telephones, § 16; 8 Witkin, Summary of Cal. Law (10th ed. 2005) Constitutional Law, § 1099.

[5] Telecommunications 372 ⚷941

372 Telecommunications
372III Telephones
372III(G) Rates and Charges
372k937 Determination of Rates
372k941 k. Financing costs; capital structure and interest. Most Cited Cases

Public Utilities Commission's credit to ratepayers of proceeds from telephone company's redemption of Class B patronage shares which company received as refund of interest paid on loans from Rural Telephone Bank (RTB) constituted an improper adjustment of previously approved rates; Commission had established rates for company based, in part, on its estimate of company's costs, which included interest on the RTB loans, and, as the patronage shares represented a reduction in that interest expense, the proceeds from the redemption of the patronage shares related to a past cost factored into the established rate. West's Ann.Cal.Pub.Util.Code § 817.

[6] Public Utilities 317A ⚷120

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak120 k. Nature and extent in general. Most Cited Cases

Public Utilities 317A ⚷123

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak123 k. Reasonableness of charges in general. Most Cited Cases

The fixing of utility rates by the Public Utilities Commission is a legislative act and the standard is that of reasonableness.

[7] Public Utilities 317A ⚷194

317A Public Utilities
317AIII Public Service Commissions or Boards
317AIII(C) Judicial Review or Intervention
317Ak188 Appeal from Orders of Commission
317Ak194 k. Review and determination in general. Most Cited Cases

Responsibility for rate fixing, insofar as the law permits and requires, is placed with the Public Utilities Commission, and unless its action is clearly shown to be confiscatory, the courts will not interfere.

[8] Public Utilities 317A ⚷120

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak120 k. Nature and extent in general. Most Cited Cases

The Public Utilities Commission does not have the power to roll back general rates already approved by it or to order refunds of amounts collected pursuant to such approved rates.

[9] Public Utilities 317A ⚷128

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges

317Ak128 k. Operating expenses. Most Cited Cases

If established rates prove insufficient to allow a utility to recover its reasonable costs, the utility cannot request compensation to remedy the revenue shortfall caused by those inadequate rates.

[10] Public Utilities 317A 129

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak129 k. Rate of return. Most Cited Cases

If established rates allow for recovery beyond the target rate of return, the Public Utilities Commission cannot require a utility to refund that additional revenue.

[11] Public Utilities 317A 120

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak120 k. Nature and extent in general. Most Cited Cases

The Public Utilities Commission has the power to fix rates prospectively only.

****845** Pillsbury WinthropShaw Pittman, San Francisco, Kevin M. Fong, James B. Young; Wagner & Wagner, Fresno, James F. Wagner and Matthew C. Wagner for Petitioner.

Frank R. Lindh, San Francisco, Helen W. Yee and Carrie G. Pratt for Respondent.

Munger, Tolles & Olson, Henry Weissmann, Los Angeles, and Hojoon Hwang, San Francisco, for Real Parties in Interest Happy Valley Telephone Company, Hornitos Telephone Company and Winterhaven Telephone Company.

Cooper, White & Cooper, San Francisco, E. Garth Black, Mark P. Schreiber, Stephen D. Kaus, Cyrus Wadia and Patrick M. Rosvall for Real Parties in Interest ****846** Calaveras Telephone Company, Cal–Ore Telephone Co., Ducor Telephone Company, Kerman Telephone Co., Sierra Telephone Company, Inc., The Siskiyou Telephone Company and Volcano Telephone Company.

***50 OPINION**

LEVY, Acting P.J.

In this original proceeding, and the two companion proceedings (F061259, F061306), 11 rural telephone companies challenge California's Public Utilities Commission (Commission) Decision No. 10–06–029, as modified by Decision No. 10–10–036 (Decision). The Decision allocates the proceeds from the redemption of Rural Telephone Bank (RTB) stock to the telephone companies' ratepayers. The subject stock was issued by the RTB in one of two ways. First, as a condition of receiving a loan from the RTB, a rural telephone company was required to purchase an amount of stock equal to 5 percent of the loan proceeds. Second, if the total interest received by the RTB from its borrowers exceeded its expenses and reserve requirements, the RTB issued patronage refunds to the rural telephone companies in the form of additional shares of stock. When the RTB was dissolved, this stock was redeemed for par value. This court issued a writ of review to consider the Decision.

Petitioner, The Ponderosa Telephone Co. (Ponderosa), contends that it owned the RTB shares. Accordingly, Ponderosa argues, the Commission's ***51** action in allocating the share proceeds to the ratepayers constituted an unlawful taking of Ponderosa's property, resulted in improper retroactive ratemaking, and was contrary to the Commission's own rules. Ponderosa further asserts that it was denied due process and that the Decision is not supported by either substantial evidence or adequate findings.

As discussed below, the Commission erred in allocating both the purchased share proceeds and the patronage share proceeds to the ratepayers. Therefore, the Decision will be annulled.

BACKGROUND

1. *Ratemaking principles and procedures.*

Ponderosa provides telephone service in rural areas of three counties and is subject to the Commission's regulatory authority. The Commission periodically establishes the rates Ponderosa charges for telephone service in general rate case proceedings using a cost-of-service or rate-of-return model. Under this structure, the Commission examines the company's costs in a test year and determines the company's revenue requirement during that test year.

The Commission examines several cost components in calculating a utility company's revenue requirement. The Commission begins by determining the value of the assets that the company has invested in to provide utility service. Property or portions thereof that are unproductive for public utility purposes are excluded. This figure is known as the "rate base."

To invest in rate base assets, a utility company raises funds by either issuing debt or selling equity. Costs are associated with each method. The company either has to pay interest to creditors on borrowed funds or pay a portion of profits or dividends to equity investors, i.e., shareholders. This cost is known as the cost of capital. The cost of capital, also known as the rate of return, multiplied by the rate base is one component of the utility company's revenue requirement.

Utility companies usually use a mix of debt financing and equity as a source of funds for their regulated activities. The ****847** reason is that, while debt is cheaper to obtain, it increases financial risks to the shareholders. Interest must be paid to creditors regardless of how the company is doing financially. On the other hand, shareholders expect an annual return that is usually greater than the cost of debt. Accordingly, companies attempt to find a middle ground between all equity financing and all debt financing.

The Commission determines a utility company's cost of capital in a three-step process. The Commission first adopts a reasonable capital structure, i.e., the proportion of debt to equity that a utility company should use to ***52** finance its capital needs. Next, the Commission calculates the company's cost of debt, based on the actual cost of the company's outstanding debt during the most recent period. Third, the Commission determines the appropriate return on the equity component of the utility company's capital by examining returns for businesses with comparable risks. Applying the resulting figures to the adopted capital structure produces the weighted cost of capital. This weighted cost of capital becomes the utility company's authorized rate of return on rate base. Alternatively, the Commission may simply apply an overall rate of return without regard to a specific capital structure.

As noted above, the Commission determines the utility company's rate base and multiplies that number by the authorized rate of return. This figure is then added to the company's operating expenses and tax costs. The sum is the company's revenue requirement, i.e., the amount needed to cover the company's costs and provide a reasonable return on its investments.

The Commission sets rates that are designed to enable a telephone company to generate sufficient revenue to meet the revenue requirement. In rural areas the cost of providing service is high. Nevertheless, the Commission limits rates for rural customers to 150 percent of urban area rates. To make up the difference between the permitted rural rates and the actual cost of service, eligible telephone companies receive subsidies from the California High Cost Fund A. Surcharges assessed against all California telephone customers provide these funds.

2. *The Rural Telephone Bank.*

In 1971, Congress created the RTB, the purpose of which was to make capital available to rural telephone providers at reasonable costs for investment in infrastructure. RTB's initial cash infusion of $600 million was provided by the federal government. In exchange, the RTB issued Class A stock to the Administrator of the Rural Utilities Service.

A second form of financing for the RTB was Class B stock. As a condition of obtaining a loan, RTB customers were required to purchase Class B stock in an amount equal to 5 percent of the RTB loan. These customers could either purchase this stock with cash or borrow additional money from the RTB to finance the stock purchase. Class B shares had a par value of $1. However, these shares were not transferable and paid no dividends.

RTB borrowers were also eligible to receive what the RTB called “patronage refunds” in the form of Class B stock. These patronage shares were a partial rebate of the interest paid to the RTB and were distributed when the RTB determined that the interest it had received from its borrowers exceeded ***53** its costs. A company's patronage refund was based solely on the dollar amount of interest it paid, not the number of Class B shares it held. Again, being Class B shares, the patronage stock could not be transferred and paid no dividends.

****848** The RTB also issued Class C stock. Class C stock had a par value of $1,000 and paid dividends. This stock could be acquired in one of two ways. RTB customers could either make discretionary purchases of Class C shares or could convert Class B shares to Class C shares at any time after the RTB loan that necessitated the purchase of the Class B shares had been repaid.

In 2005, the RTB board, with congressional approval, dissolved the RTB and initiated the stock redemption process. Beginning in 2006, all Class B and Class C shares were redeemed at par value, i.e., $1 per share and $1,000 per share respectively. In November 2007, the RTB distributed its remaining funds as residual amounts to all Class B shareholders at a rate of $0.04435 per share.

3. ***Ratemaking treatment of the RTB stock.***

The Commission did not explicitly address the appropriate ratemaking treatment of the RTB stock for the years 1972 through 1996. The first direct Commission action on this stock occurred 25 years after the telephone companies' initial loans when the Commission conducted general rate cases for most of those companies.

In 1997 Ponderosa filed a general rate case advice letter with the Commission. At that time, Ponderosa proposed to include the Class B stock obtained with 5 percent of RTB loan proceeds in its rate base. However, the Commission rejected this request. The Commission further directed Ponderosa to file an application requesting the Commission to determine the appropriate ratemaking treatment for the gain on the RTB stock when those shares were redeemed.

The Commission also excluded the RTB stock from the outstanding balance of long-term debt. This exclusion resulted in an increase in Ponderosa's cost of debt. However, the exclusion of the RTB shares in calculating Ponderosa's long-term cost of debt had no effect on its authorized rate of return. Rather, the Commission adopted a generic 10 percent authorized rate of return without reference to Ponderosa's actual cost of debt.

Beginning in 2004, the Commission authorized Ponderosa to include its purchased Class B shares in rate base. Accordingly, Ponderosa earned its authorized rate of return on those shares from January 1, 2004 until April 11, 2006.

54 4.** ***The underlying administrative proceeding.

In December 2007, following the final RTB stock redemption payment, Ponderosa, together with the other rural telephone companies, filed an application with the Commission seeking a ratemaking determination regarding any gain on the redemption. These companies proposed to credit the ratepayers with 67 percent of the gain, i.e., the $0.04435 per share residual amount, for the purchased Class B shares that 5 of the 11 companies included in rate base between 2004 and 2006. For Ponderosa, this amount was $2,558.

The proposal to limit the credit to 67 percent of the gain was based on an earlier Commission decision regarding allocation of gains on sale of utility assets. In that decision, D.06–05–041, as modified by D.06–12–043 (Gains on Sale Decision), the Commission determined that the gain on the sale of nondepreciable utility assets included in rate base be allocated 67 percent to the ratepayers and 33 percent to the shareholders. The Commission concluded that incidence of risk is the best determinate of how to allocate gains and losses on sale. Accordingly, because ratepayers bear the major portion of risks and ****849** provide a return on utility assets in rate base, they should share in the associated gain. However, the Commission also held that, where property is never in rate base, all gains or losses should accrue to the shareholders.

The Administrative Law Judge (ALJ) assigned to the case issued a proposed decision in September 2009. The ALJ concluded that the telephone companies had not met their burden of proving that the shareholders incurred the costs of acquiring the stock. Finding that the purchase price of the RTB stock was a cost of obtaining a loan and was included in evaluating the companies' cost of capital in setting the revenue requirement to be recovered from the ratepayers, the ALJ determined that the ratepayers incurred the cost. Accordingly, the ALJ concluded that the ratepayers should be credited with all stock redemption proceeds.

In response, the telephone companies moved to reopen the record to provide additional evidence and argument. The ALJ granted this motion. The telephone companies filed additional evidence, including verified written testimony of two experts and a full accounting of all RTB stock proceeds, and requested that the Commission take official notice of its past decisions and resolutions involving the companies and relating to the RTB stock.

The ALJ issued revised proposed decisions in December 2009 and February 2010. The telephone companies again moved to reopen the record arguing ***55** that three new evidentiary issues appeared in the revised proposed decisions. The companies objected to the revised decisions' reference to previous Commission decisions and income tax liability and the suggestion that the companies had agreed to a different treatment of the RTB stock in the 1997 rate cases. The ALJ denied this motion.

5. *The Commission's Decision.*

In the Decision, the Commission found that the 11 rural telephone companies received approximately $31 million from the RTB stock redemption and that this amount should be credited to the ratepayers.

The Commission first noted that the RTB stock was a public utility asset and the 2006 redemption amounted to a sale of this asset. Accordingly, the Commission turned to its Gains on Sale Decision for guidance in resolving this case. The Commission further pointed out that under Public Utilities Code [FN1] section 817, it could only authorize the encumbrance of public utility property for public utility purposes.

FN1. All further statutory references are to the Public Utilities Code.

The Commission considered the Class B patronage shares and the purchased Class B shares separately. Regarding the patronage shares, the Commission concluded that, because the interest payments were supplied by the ratepayers through the regulated revenue requirement, the ratepayers furnished the funds that led to the patronage refund stock. The Commission held that, therefore, both the par value redemption and the above par payments on the patronage refund shares should benefit the ratepayers, i.e., the parties who bore the original costs of acquiring the stock.

The Commission found that the shares that were required to be purchased with 5 percent of the loan funds were a cost of obtaining the loan, not a shareholder funded capital purchase. Because these capital costs were reflected in the companies' regulated revenue requirement and recovered from the ratepayers, the Commission concluded****850** that the redemption proceeds should be returned to the ratepayers.

DISCUSSION

1. *Standard of review.*

Under section 1756, this court has jurisdiction to review Commission decisions through petitions for writ of review. (§ 1756, subd. (a).) Such review is discretionary rather than mandatory. ***56**(*Southern Cal. Edison Co. v. Public Utilities Com.* (2005) 128 Cal.App.4th 1, 9, 26 Cal.Rptr.3d 700.) Nevertheless, because petitions for writ of review serve in effect as appeals, they are not to be summarily denied on policy grounds unrelated to their merits. (*Pacific Bell v. Public Utilities Com.* (2000) 79 Cal.App.4th 269, 282, fn. 8, 93 Cal.Rptr.2d 910.)

This court's review of the Decision is governed by section 1757. Pursuant to that section, review cannot extend further than to determine whether (1) the Commission acted without, or in excess of, its powers or jurisdiction; (2) the Commission acted contrary to a statute or to the state or federal constitution; (3) the Commission's decision is not supported by the findings or those findings are not supported by substantial evidence; or (4) the Commission abused its discretion. (§ 1757, subd. (a).)

[1][2] Moreover, the Commission is not an ordinary administrative agency, but, rather is a constitutional body with broad legislative and judicial powers. Accordingly, the Commission's decisions are presumed valid. (*Southern Cal. Edison Co. v. Public Utilities Com.* (2000) 85 Cal.App.4th 1086, 1096–1097, 102 Cal.Rptr.2d 684.) However, where a Commission decision is challenged on the ground that it violates a constitutional right, the reviewing court must exercise independent judgment on the law and the facts and the Commission's findings or conclusions material to the constitutional question shall not be final. (§ 1760.)

2. *The purchased Class B shares.*

As outlined above, as a condition of receiving loans from the RTB to be used to provide public utility service, the telephone companies were required to purchase Class B stock in an amount equal to 5 percent of the loan proceeds. The telephone companies could either purchase this stock with cash or borrow additional money from the RTB to finance the stock purchase. Thus, this 5 percent purchase was an investment the telephone companies were required to make in order to borrow money to provide public utility service. Moreover, the telephone companies bore the risk of loss if the purchased shares became worthless in that the telephone companies were responsible for paying back the entire amount of the loan, including the portion used to fund the stock purchase.

A public utility may only issue evidence of equity or indebtedness for purposes related to providing public utility service to customers and such issue must be authorized by the Commission. (§§ 817, 818.) The Commission found that, because the telephone companies could only encumber their property to provide public utility service (§§ 817, 818) and the loans were used to provide public utility service as required, the purchased shares were ***57** public utility assets that fell within the scope of the Gains on Sale Decision. Under that decision, upon the sale of nondepreciable public utility property, the acquisition cost of that property is allocated to the shareholders and the gains or losses are allocated 67 percent to the ratepayers and 33 percent to the shareholders. However, this disposition only applies to assets that were in rate base. For non-utility assets ****851** held out of rate base, all gains and losses accrue to the shareholders.

As explained by the Commission in the Decision, the central question at issue was who owned the RTB stock. The telephone companies purchased the shares but financed them with debt. However, the fact that a utility incurs debt to acquire an asset does not divest the utility of ownership of that asset. Rather, the Commission requires a utility to finance its capital needs with a balance of debt and equity and adopts what it considers to be a reasonable capital structure, i.e., debt to equity ratio, for that utility. For the rural telephone companies the Commission concluded that 40 percent debt and 60 percent equity was reasonable. As noted by the Commission, such a balance is necessary because ratepayers pay more on a high equity company while a high debt company faces higher risks.

[3] Moreover, it has long been established that "[b]y paying bills for service [utility customers] do not acquire any interest, legal or equitable, in the property used for their convenience or in the funds of the company." (*Board of Commrs. v. N.Y. Tel. Co.* (1926) 271 U.S. 23, 32, 46 S.Ct. 363, 70 L.Ed. 808.) Rather, "[c]ustomers pay for service, not for the property used to render it." (*Ibid.*) The revenue paid by the customers belongs to the company. (*Id.* at p. 31, 46 S.Ct. 363.) Similarly, in the Gains on Sale Decision, the Commission explicitly rejected the notion that ratepayers hold legal title to utility property by virtue of bearing costs associated with utility property, including carrying costs. As noted by Justice Marshall in his concurring opinion, the fact that the utility recovers its costs through rates cannot affect the utility's ownership of its property. (*Pacific Gas & Elec. Co. v. Public Util. Comm'n* (1986) 475 U.S. 1, 22–23, fn. 1, 106 S.Ct. 903, 89 L.Ed.2d 1.)

Despite this established rule, the Commission concluded that the proceeds from the Class B stock that was purchased by the telephone companies should benefit the ratepayers. In reaching this determination, the Commission relied on the ratemaking history for these shares.

The Commission first noted that it did not explicitly address the appropriate ratemaking treatment until 25 years after the initial loans when, in 1997, it conducted general rate cases for most of the companies. In these 1997 decisions, the Commission rejected the telephone companies' requests to ***58** include the purchased shares in rate base and excluded RTB stock from the outstanding balance of long-term debt. However, the Commission changed its treatment of this stock for five companies, including Ponderosa, and included the shares in rate base between 2004 and 2006. The Commission explained that, although it had found the shares to be public utility assets, when it rejected the companies' 1997 requests to place the shares in rate base, it *perceived* the cost of the stock as a cost of obtaining the loan, not as a shareholder funded capital purchase. Moreover, the Commission stated, these capital costs were reflected in the companies' regulated revenue requirement and thus recovered from the ratepayers. The Commission found that its decision to adopt an overall cost of capital in 1997 without specific regard to each element of debt to be insignificant. The Commission also dismissed the recent inclusion of a small share of the stock in rate base as being insufficient to change its ratemaking conclusion.

Based on the above analysis, the Commission placed the burden on the telephone companies to demonstrate that the shareholders separately funded the purchased stock as an unregulated investment, i.e., an investment held out of rate ****852** base that should be allocated to the shareholders, and concluded that they did not meet this burden. Moreover, the Commission noted that because the RTB mortgages were limited by section 817 to public utility purposes, those purchased shares could not be an unregulated investment to be held by the shareholders out of rate base. In other words, this required investment was for public utility purposes and thus cannot be considered a shareholder private investment, i.e., it is a public utility asset, but the shareholders must demonstrate that it was a shareholder private investment before they are entitled to recover the acquisition cost of this public utility asset.

The Commission's Decision on the purchased stock is incorrect. As noted above, the telephone companies were required to invest in the Class B stock to provide utility service and therefore it was a public utility asset. The fact that this investment was funded through debt, and thus included in the companies' costs of capital, did not transfer ownership of this stock to the ratepayers. The Commission requires the companies to employ debt as part of their capital structure. If the repayment of debt through regulated rates were found to impact ownership of public utility assets, and if for example, the companies were required to maintain a 40 percent long-term debt ratio, the ratepayers would own 40 percent of the public utility assets. This is not the law. (*Board of Commrs. v. N.Y. Tel. Co., supra,* 271 U.S. at pp. 31–32, 46 S.Ct. 363.)

Further, the Commission's "perception" of the character of the purchased shares is not determinative of the proper ratemaking treatment. Again, the telephone companies were required to make this investment as part of providing public utility service and bore the risk of loss. Being an asset ***59** required for public utility service, the stock should have been included in rate base. Clearly, the Commission later came to this conclusion when it included these shares in rate base for the five companies that filed general rate cases after 1997. The fact that these purchased shares were not universally held in rate base does not change their nature. They were a regulated investment that should have been in rate base.

The Commission's contrary and circular reasoning as to the character of these shares is not persuasive. The Commission's analysis begins with finding that the purchased stock is a public utility asset, the redemption of which is a public utility asset sale subject to the Gains on Sale Decision. The Commission then "start[s] with the proposition that traditional ratemaking principles, as reflected in the [Gains on Sale Decision], would indicate that an asset, such as shares of stock, purchased with loan proceeds secured by mortgages on public utility property as a requirement for Commission-approved loans would be used and useful public utility property that would properly be carried in a public utility's rate base." The Commission then notes that only a small share of the total amount of the purchased RTB stock has ever been in rate base, and only since 2004. However, as noted above, the reason for the shares not being in rate base, at least since 1997, was the Commission's decision to "opt[ ] for a 'different treatment' for the stock." The Commission then concludes that, to be entitled to the proceeds of the stock redemption, the shareholders must demonstrate that they separately funded the purchased stock as an unregulated investment. However, the Commission explains, such a result is precluded by the Commission having approved the loans because, under section 817, the shareholders cannot encumber public utility property for their private interests. In other words, because we, the ****853** Commission, decided at one point that these shares that would otherwise be properly carried in rate base should not be carried in rate base, you, the shareholders are precluded from receiving the proceeds to which you otherwise would have been entitled. This analysis cannot stand. The Commission cannot change the character of a public utility asset by improperly excluding it from rate base.

[4] Accordingly, the Class B shares purchased by Ponderosa were public utility assets that were owned by Ponderosa. Therefore, the Commission's decision to credit the par value redemption proceeds of those shares to the ratepayers constituted an illegal appropriation of Ponderosa's property. (*Brown v. Legal Foundation of Washington* (2003) 538 U.S. 216, 233, 235–236, 123 S.Ct. 1406, 155 L.Ed.2d 376; *Webb's Fabulous Pharmacies, Inc. v. Beckwith* (1980) 449 U.S. 155, 163–164, 101 S.Ct. 446, 66 L.Ed.2d 358.) Ponderosa is entitled to all proceeds from the redemption of those shares with the exception of the gain, i.e., the $0.04435 per share residual amount, attributable to the shares in rate base between January 1, 2004 and April 11, 2006. ***60** That gain should be allocated 67 percent to the ratepayers and 33 percent to the shareholders under the Gains on Sale Decision.

In light of this conclusion, it is unnecessary to address Ponderosa's assertion that the Commission's allocation of the purchased shares to the ratepayers is not supported by sufficient evidence or findings.

3. *The patronage Class B shares.*

[5] As noted above, the telephone companies received patronage Class B shares as refunds of interest paid on the RTB loans. These patronage shares were issued in the companies' names on an annual basis in proportion to the interest the companies paid on their RTB loans. The telephone companies analyze these shares in the same manner as the purchased shares. However, the different nature of the patronage shares mandates a separate analysis.

The Commission found that the patronage stock was a regulated asset and that its redemption fell within the Gains on Sale Decision. The Commission pointed out that there was no dispute that each company's regulated revenue requirement included the cost of debt. The Commission then explained that, implicit in the Gains on Sale Decision is the concept that, upon sale of a regulated asset, the original cost is returned to those who paid for the asset. Since the patronage shares were refunds of interest paid on the RTB loans and the interest payments were supplied by ratepayers through the regulated revenue requirement, the Commission determined that the redemption amount should benefit the ratepayers, i.e., those who bore the original costs of acquiring the stock.

The Commission further concluded that the ratepayers should also be entitled to the residual $0.04435 per share. The Commission relied on the absence of the factors that trigger the Gains on Sale Decision's sharing formula. Contrary to the usual sale of a utility asset, the shareholders did not provide the capital at risk in acquiring the asset and, moreover, were entirely passive owners. The Commission additionally noted that, because the ratepayers, and not the shareholders, funded this asset, any revenue realized from the asset should be credited to the ratepayers because to do otherwise would result in a windfall for the shareholders.

Ponderosa contends that the Commission acted in excess of its authority when it allocated the patronage stock redemption proceeds to the ratepayers because this ****854** allocation constituted retroactive ratemaking. Ponderosa asserts that the effect of this allocation is to reduce the past rates based on a reduction in the cost of loans made by the RTB. In other words, because the patronage shares reflect a reduction in the cost of the loans, i.e., an interest ***61** rebate, the Commission's refund order flows back to the ratepayers the cost savings that Ponderosa realized on past loan payments that were considered in the general rate proceedings. Ponderosa is correct.

[6][7][8][9][10][11] The fixing of utility rates by the Commission is a legislative act and the standard is that of reasonableness. (*Pacific Tel. & Tel. Co. v. Public Util. Com.* (1965) 62 Cal.2d 634, 647, 44 Cal.Rptr. 1, 401 P.2d 353.) Responsibility for rate fixing, insofar as the law permits and requires, is placed with the Commission, and unless its action is clearly shown to be confiscatory, the courts will not interfere. (*Ibid.*) Nevertheless, the Commission does not have the power to roll back general rates already approved by it or to order refunds of amounts collected pursuant to such approved rates. (*Id.* at p. 650, 44 Cal.Rptr. 1, 401 P.2d 353.) Thus, if established rates prove insufficient to allow a utility to recover its reasonable costs, the utility cannot request compensation to remedy the revenue shortfall caused by those inadequate rates. Similarly, if established rates allow for recovery beyond the target rate of return, the Commission cannot require a utility to refund that additional revenue. In other words, the Commission has the power to fix rates prospectively only. (*Southern Cal. Edison Co. v. Public Utilities Com.* (1978) 20 Cal.3d 813, 816, 144 Cal.Rptr. 905, 576 P.2d 945 (*Southern Cal. Edison*).)

Here, the Commission established rates for Ponderosa based, in part, on its estimate of Ponderosa's costs. These costs included interest on the RTB loans. The RTB patronage shares represented a reduction in this interest expense. Thus, when the RTB redeemed the patronage shares, those proceeds related to a past cost that was factored into the rate established at that time. Accordingly, when the Commission credited the redemption proceeds to the ratepayers, it was, in effect, adjusting previously established rates to account for the cost savings the telephone companies realized on their past loan payments. Because the Commission's decision on the patronage shares is based on costs that were incurred in the past and used to establish prior general rates, the Decision violates the rule against retroactive ratemaking. The Commission relies on a cost forecast to set general rates and cannot reset those rates when the actual costs differ from the forecast. By doing so here, the Commission acted in excess of its authority. Therefore, the Decision is invalid.

In analogous situations, courts have made similar rulings. For example, in *Public Utilities Com'n of State of Cal. v. F.E.R.C.* (D.C.Cir.1990) 894 F.2d 1372, a natural gas company used accelerated depreciation when computing taxes. However, in estimating its cost of service for ratemaking purposes, the gas company computed its tax expense as if it had used ordinary depreciation. Accordingly, the gas company was able to charge its customers more in tax costs in the early years of an ***62** asset's life than it paid out in taxes. These temporary tax savings went into a deferred tax account, earmarked for future tax liabilities. However, due to a change in the law, the gas company stopped setting rates based on cost-of-service pricing. Thus, the question arose as to the proper disposition of the funds in the gas company's deferred tax account, funds composed ****855** of rate revenue that the gas company had already collected.

The court held that the deferred tax funds should be retained by the gas company. Any other result would violate the rule against retroactive ratemaking. The court noted that a refund of such property, or its earnings, would effectively force the gas company to return a portion of rates approved by the Federal Energy Regulatory Commission and collected by the gas company. (*Public Utilities Com'n of State of Cal. v. F.E.R.C., supra,* 894 F.2d at p. 1383.) The court concluded that the Federal Energy Regulatory Commission's order to credit the earnings on the deferred tax funds to rates to be charged going forward was in substance a retroactive adjustment of prior rates and reversed that portion of the order. The court observed that the "rule against such revision operates sometimes to protect customers from surcharges and at others to protect gas companies from refunds; its equity lies in its steady application regardless of what party is seeking to reexamine the past." (*Id.* at p. 1384.)

Here, as in *Public Utilities Com'n of State of Cal. v. F.E.R.C., supra,* 894 F.2d 1372, the funds at issue relate to utility costs that were paid in the past, i.e., the cost of debt reflected in the patronage shares and the tax costs reflected in the deferred tax account. In both cases, the agency set rates based on a forecast of costs and the agency cannot reset those rates when the actual costs turn out to be different than the forecast. The rule against retroactive ratemaking prevents the agency from forcing a utility to disgorge the proceeds of rates that have been finally approved and collected, as well as the fruits of those proceeds. (*Id.* at p. 1384; see also *Associated Gas Distributors v. F.E.R.C.* (D.C.Cir.1990) 898 F.2d 809, 810.)

The Commission relied on *Southern Cal. Edison, supra,* 20 Cal.3d 813, 144 Cal.Rptr. 905, 576 P.2d 945, in analyzing the situation presented here. In *Southern Cal. Edison,* the Commission set a general rate for Southern California Edison Company (Edison). In estimating Edison's costs, the Commission based Edison's fuel costs for 1972 on actual prices paid in the period preceding the decision. However, shortly thereafter, Edison's fossil fuel costs rose substantially. In response, Edison applied for immediate rate relief and for authority to amend its tariff to include an adjustment clause permitting periodic future billing adjustments to reflect future fuel cost increases. The Commission granted an immediate rate increase and authorized the requested fuel clause. (*Id.* at p. 817, 144 Cal.Rptr. 905, 576 P.2d 945.)

***63** Over the next two years, Edison invoked the fuel clause at every opportunity and raised its rates. However, due to a weather related increase in the availability of hydroelectric power, a much cheaper source of energy than fossil fuels, Edison spent considerably less for fossil fuels than it had estimated in computing its adjustment under the fuel clause. Accordingly, Edison was left holding more money than it needed to offset increased fuel costs.

The Commission required Edison to amortize these over-collections through billing credits to its customers. Edison objected on the ground that, because these funds were lawfully collected pursuant to an authorized rate structure, the order to return them constituted illegal retroactive ratemaking. The California Supreme Court disagreed and ruled in favor of the Commission.

The *Southern Cal. Edison* court observed that, before there can be retroactive ratemaking there must at least be ratemaking. ****856**(*Southern Cal. Edison, supra,* 20 Cal.3d at p. 817, 144 Cal.Rptr. 905, 576 P.2d 945.) The purpose of the fuel clause was primarily to permit Edison to "recover" its increased fuel costs in an expedited manner on a dollar-for-dollar basis. (*Id.* at p. 819, 144 Cal.Rptr. 905, 576 P.2d 945.) The court concluded that, in authorizing Edison every few months to adjust its rates by operation of the fuel clause, the Commission was not engaging in ratemaking. (*Id.* at pp. 829–830, 144 Cal.Rptr. 905, 576 P.2d 945.) Ratemaking requires a full hearing in which many variables are taken into account and broad policies are formulated. (*Id.* at p. 828, 144 Cal.Rptr. 905, 576 P.2d 945.) Such a hearing is not required each time the rate is changed by application of an adjustment clause. (*Id.* at p. 829, 144 Cal.Rptr. 905, 576 P.2d 945.) Accordingly, the rates fixed by operation of the fuel clause were not " 'general rates' but 'extraordinary rates not created by or in a general rate proceeding.' " (*Id.* at p. 830, fn. 21, 144 Cal.Rptr. 905, 576 P.2d 945.) Because the increased charges were not the products of ratemaking, the billing credits required by the Commission were not rendered inviolable by the rule against *retroactive* ratemaking. (*Id.* at p. 830, 144 Cal.Rptr. 905, 576 P.2d 945.) "To put it another way, the commission's decision to further adjust those rates so as to compensate for substantial past overcollections may well be retroactive in effect, but it is not retroactive *ratemaking.*" (*Ibid.,* fn. omitted.)

Contrary to the Commission's position, *Southern Cal. Edison* does not dictate the result here. In this case, there were no special surcharges or " 'extraordinary rates not created by or in a general rate proceeding.' " Rather, the rates were set by the Commission in general rate proceedings held in 1997 and in subsequent years. Those Commission decisions constituted "general ratemaking." The Commission's allocation of the patronage share redemption proceeds to the ratepayers rests on the premise that the amounts collected pursuant to the approved general rates were excessive because they overstated the cost of debt. Thus, the Decision retroactively revises costs that formed the basis for prior general rates. This is precisely the type of action ***64** prohibited by the retroactive ratemaking doctrine. Such a roll back of general rates already approved by the Commission and refund of amounts collected pursuant to such approved rates constitutes retroactive ratemaking and therefore is invalid. (*Pacific Tel. & Tel. Co. v. Public Util. Com., supra,* 62 Cal.2d at p. 650, 44 Cal.Rptr. 1, 401 P.2d 353.)

In sum, the Commission's decision to credit the patronage share redemption proceeds to the ratepayers adjusts previously approved rates. Moreover, these rates were established in general ratemaking proceedings. Therefore, the Commission's decision violates the retroactive ratemaking doctrine. Accordingly, that decision was in excess of the Commission's authority and is invalid.

DISPOSITION

The Decision is annulled. The cause is remanded to the Commission for reallocation of the Class B share redemption proceeds in accordance with this opinion. Costs on appeal are awarded to petitioner.

WE CONCUR: GOMES and KANE, JJ.

Cal.App. 5 Dist.,2011.
Ponderosa Telephone Co. v. Public Utilities Com.
197 Cal.App.4th 48, 127 Cal.Rptr.3d 844, 11 Cal. Daily Op. Serv. 8385, 2011 Daily Journal D.A.R. 10,034

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In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Annual Revenues for Electric Service
ER-2011-0028
YE-2011-0116

Missouri Public Service Commission
July 13, 2011

REPORT AND ORDER

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For the Missouri Retailers Association.

BY THE COMMISSION.

CHIEF REGULATORY LAW JUDGE: Morris L. Woodruff

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The Missouri Public Service Commission, having considered all the competent and substantial evidence upon the whole record, makes the following findings of fact and conclusions of law. The positions and arguments of all of the parties have been considered by the Commission in making this decision. Failure to specifically address a piece of evidence, position, or argument of any party does not indicate that the Commission has failed to consider relevant evidence, but indicates rather that the omitted material was not dispositive of this decision.

SUMMARY

This order allows Ameren Missouri to increase the revenue it may collect from its Missouri customers by approximately $172 million based on the data contained in the Revised True-up Reconciliation filed by the Missouri Public Service Commission Staff on May 16, 2011.

PROCEDURAL HISTORY

On September 3, 2010, Union Electric Company, d/b/a Ameren Missouri filed tariff sheets designed to implement a general rate increase for electric service. The tariff would have increased Ameren Missouri's annual electric revenues by approximately $263 million. The tariff revisions carried an effective date of October 3, 2010.

By order issued on September 7, 2010, the Commission suspended Ameren Missouri's general rate increase tariff until July 31, 2011, the maximum amount of time allowed by the controlling statute.[FN1] In the same order, the Commission directed that notice of Ameren Missouri's tariff filing be provided to interested parties and the public. The Commission also established October 4, 2010, as the deadline for submission of applications to intervene. The following parties filed applications and were allowed to intervene: The International Brotherhood of Electrical Workers Locals 2, 309, 649, 702, 1439, and 1455, AFL-CIO and International Union of Operating Engineers Local 148 AFLCIO (collectively the Unions); The Missouri Industrial Energy Consumers (MIEC);[FN2] The Missouri Energy Group (MEG);[FN3] The Missouri Department of Natural Resources (MDNR); Missouri-American Water Company; The Consumers Council of Missouri; AARP; The Missouri Retailers Association; The Natural Resources Defense Council; the Missouri Coalition for the Environment, d/b/a Renew Missouri; the Cities of O'Fallon, Creve Coeur, University City, Olivette, St. Ann, Kirkwood, Bellfontaine Neighbors, Florissant, Richmond Heights, Ballwin, Brentwood, St. John, Sunset Hills, the Village of Twin Oaks, the Village of Riverview, and the St. Louis County Municipal League (the Municipal Group); the Midwest Energy Users' Association (MEUA);[FN4] and Charter Communications, Inc.

FN1.Section 393.150, RSMo 2000.

FN2. The following members of MIEC were allowed to intervene as individual entities and as an association: Anheuser-Busch Companies, Inc.; BioKyowa, Inc.; The Boeing Company; Doe Run; Enbridge; Explorer Pipeline; General Motors Corporation; GKN Aerospace; Hussmann Corporation; JW Aluminum; Monsanto; Precoat Metals; Proctor & Gamble Company; Nestlé Purina PetCare; Noranda Aluminum; Saint Gobain; Solutia; and U.S. Silica Company.

FN3. The members of MEG are Barnes-Jewish Hospital; Buzzi Unicem USA, Inc.; and SSM HealthCare.

FN4. The only member of MEUA for this case is Wal-Mart Stores, Inc.

On November 10, 2010, the Commission established the test year for this case as the 12-month period ending March 31, 2010, trued-up as of February 28, 2011. In its November 10 order, the Commission established a procedural schedule leading to an evidentiary hearing regarding Ameren Missouri's general rate increase tariff.

In February and March 2011, the Commission conducted fourteen local public hearings at various sites around Ameren Missouri's service area. At those hearings, the Commission heard comments from Ameren Missouri's customers and the public regarding Ameren Missouri's request for a rate increase.

In compliance with the established procedural schedule, the parties prefiled direct, rebuttal, and surrebuttal testimony. The evidentiary hearing began on April 26, 2011, and continued through May 20. The parties indicated they had no contested true-up issues and the Commission cancelled the scheduled true-up hearing. The parties filed post-hearing briefs on June 1, 2011, with reply briefs following on June 13. Based on the revised true-up reconciliation filed by Staff on May 16, Ameren Missouri has reduced its rate increase request to $211,183,446.

ADMISSION OF TRUE-UP DOCUMENT INTO EVIDENCE

A true-up hearing was originally scheduled for May 23 and 24. On May 16, Gary Weiss filed true-up direct testimony consisting of many pages of accounting schedules detailing true-up numbers. There were no true-up issues and on May 20, the Commission cancelled the true-up hearing. Through an oversight, Mr. Weiss's true-up testimony was never admitted into evidence. However, the accounting schedules attached to that testimony are cited in the briefs and in this report and order. Therefore, the Commission will admit the True-Up Direct Testimony of Gary S. Weiss into evidence and will assign that document exhibit number 174.

THE PARTIAL STIPULATIONS AND AGREEMENTS

During the course of the evidentiary hearing, various parties filed three nonunanimous partial stipulations and agreements resolving issues that would otherwise have been the subject of testimony at the hearing. No party opposed those partial stipulations and agreements. As permitted by its regulations, the Commission treated the unopposed partial stipulations and agreements as unanimous.[FN5] After considering the stipulations and agreements, the Commission approved them as a resolution of the issues addressed in those agreements.[FN6] The issues resolved in those stipulations and agreements will not be further addressed in this report and order, except as they may relate to any unresolved issues.

FN5. Commission Rule 4 CSR 240-2.115(C).

FN6. The Commission issued its *Order Approving Stipulations and Agreements* on June 1, 2011.

On May 12, 2011, Public Counsel, MIEC, AARP, the Consumers Council of Missouri, the Missouri Retailers, MEUA, and MEG filed a non-unanimous stipulation and agreement that would have resolved various class cost of service and rate design issues. The Municipal Group opposed that non-unanimous stipulation and agreement. Similarly, on May 18, Ameren Missouri and MDNR filed a non-unanimous stipulation and agreement regarding evaluation of the low-income weatherization program. Public Counsel opposed that stipulation and agreement. As provided in the Commission's rules, the Commission will consider those stipulations and agreements to be merely a position of the signatory parties to which no party is bound.[FN7] The issues that were the subject of those stipulations and agreements will be determined in this report and order.

FN7. Commission Rule 4 CSR 240-2.115 (2)(D).

OVERVIEW

Ameren Missouri is an investor-owned integrated electric utility providing retail electric service to large portions of Missouri, including the St. Louis Metropolitan area. Ameren Missouri has approximately 1.2 million retail electric customers in Missouri, more than 1 million of whom are residential customers.[FN8] Ameren Missouri also operates a natural gas utility in Missouri but the rates it charges for natural gas are not at issue in this case.

FN8. Baxter Direct, Ex. 100, Page 4, Lines 19-20.

Ameren Missouri began the rate case process when it filed its tariff on September 3, 2010. In doing so, Ameren Missouri asserted it was entitled to increase its retail rates by $263 million per year, an increase of approximately 11 percent.[FN9] Ameren Missouri attributed approximately $200 million of the proposed increase to energy infrastructure investments, environmental controls and other reliability costs to meet customers' expectations for more reliable and cleaner energy.[FN10] The company attributed another $70 million of that increase to the rebasing of fuel costs that would otherwise be passed through to customers by operation of the company's existing fuel adjustment clause.[FN11]

FN9. Baxter Direct, Ex. 100, Page 5, Lines 16-17.

FN10. Baxter Direct, Ex. 100, Page 5, Lines 20-22.

FN11. Baxter Direct, Ex. 100, Page 6, Lines 19-23.

Ameren Missouri set out its rationale for increasing its rates in the direct testimony it filed along with its tariff on September 3, 2010. In addition to its filed testimony, Ameren Missouri provided work papers and other detailed information and records to the Staff of the Commission, Public Counsel, and to the intervening parties. Those parties then had the opportunity to review Ameren Missouri's testimony and records to determine whether the requested rate increase was justified.

Where the parties disagreed, they prefiled written testimony to raise those issues to the attention of the Commission. All parties were given an opportunity to prefile three rounds of testimony - direct, rebuttal, and surrebuttal. The process of filing testimony and responding to the testimony filed by other parties revealed areas of agreement that resolved some issues and areas of disagreement that revealed new issues. On April 21, the parties filed a list of the issues they asked the Commission to resolve. The Commission will address those issues in the order submitted by the parties.

CONCLUSIONS OF LAW REGARDING JURISDICTION

A. Ameren Missouri is a public utility, and an electrical corporation, as those terms are defined in Section 386.020(43) and (15), RSMo (Supp. 2010). As such, Ameren Missouri is subject to the Commission's jurisdiction pursuant to Chapters 386 and 393, RSMo.

B. Section 393.140(11), RSMo 2000, gives the Commission authority to regulate the rates Ameren Missouri may charge its customers for electricity. When Ameren Missouri filed a tariff designed to increase its rates, the Commission exercised its authority under Section 393.150, RSMo 2000, to suspend the effective date of that tariff for 120 days beyond the effective date of the tariff, plus an additional six months.

CONCLUSIONS OF LAW REGARDING THE DETERMINATION OF JUST AND REASONABLE RATES

A. In determining the rates Ameren Missouri may charge its customers, the Commission is required to determine that the proposed rates are just and reasonable.[FN12] Ameren Missouri has the burden of proving its proposed rates are just and reasonable.[FN13]

FN12. Section 393.150.2, RSMo 2000.

FN13. *Id.*

B. In determining whether the rates proposed by Ameren Missouri are just and reasonable, the Commission must balance the interests of the investor and the consumer.[FN14] In discussing the need for a regulatory body to institute just and reasonable rates, the United States Supreme Court has held as follows:

FN14. *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603, (1944).

Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[FN15]

FN15. *Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia,* 262 U.S. 679, 690 (1923).

In the same case, the Supreme Court provided the following guidance on what is a just and reasonable rate:
What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[FN16]

FN16. *Id.* at 692-93.

The Supreme Court has further indicated:

'[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[FN17]

FN17. *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (citations omitted).

C. In undertaking the balancing required by the Constitution, the Commission is not bound to apply any particular formula or combination of formulas. Instead, the Supreme Court has said:
Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.[FN18]

FN18. *Federal Power Commission v. Natural Gas Pipeline Co.* 315 U.S. 575, 586 (1942).

D. Furthermore, in quoting the United States Supreme Court in *Hope Natural Gas*, the Missouri Court of Appeals said:

[T]he Commission [is] not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' … Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed which is controlling. It is not theory but the impact of the rate order which counts.[FN19]

FN19.*State ex rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n,* 706 S.W. 2d 870, 873 (Mo. App. W.D. 1985).

THE RATE MAKING PROCESS

The rates Ameren Missouri will be allowed to charge its customers are based on a determination of the company's revenue requirement. Ameren Missouri's revenue requirement is calculated by adding the company's operating expenses, its depreciation on plant in rate base, taxes, and its rate of return multiplied by its rate base. The revenue requirement can be expressed as the following formula:

Revenue Requirement = E + D + T + R(V-AD+A)
Where: E = Operating expense requirement
D = Depreciation on plant in rate base
T = Taxes including income tax related to return
R = Return requirement
(V-AD+A) = Rate base
For the rate base calculation:
V = Gross Plant
AD = Accumulated depreciation
A = Other rate base items

All parties accept the basic formula. Disagreements arise over the amounts that should be included in the formula.

THE ISSUES

1. Overview and Policy:

A. What “cost of service” and/or regulatory policy considerations, if any, should guide the Commission's decision of the issues in this case?

B. Can the Commission consider and rely on the testimony of ratepayers at local public hearings in determining just and reasonable rates? If so, how should the Commission take this testimony into account, if at all?

Although this was identified as an issue by the parties, there is no actual overview and policy issue that will require resolution by the Commission. Rather, some of the parties ask the Commission to explain how it views its role as a regulator and in particular, explain how it deals with the testimony it receives from ratepayers at local public hearings. The Commission will accept this invitation to explain its role.

As its name implies, the Public Service Commission was created and exists primarily to serve the public. In a case decided just a few years after this Commission was created, the Missouri Supreme Court stated that the spirit of the act establishing the Public Service Commission is to protect the public. In the words of the court, “[t]he protection given the utility is incidental.”FN20

FN20.*State ex rel. Electric Co. of Missouri v. Atkinson et al.,* 275 Mo. 325, 204 S.W. 897, 899 (Mo banc 1918).

Some parties suggest that if the Commission is to serve the public interest, it must bow to the popular will expressed at the various local public hearings and eliminate or reduce as far as possible any rate increase requested by the utility. However, that is not the law under which the Commission operates. Furthermore, a Commission policy that destroyed the profitability of the utility would ultimately harm the public the Commission is obligated to serve.

As the Commission indicated in a previous section of this Report and Order, it is required to balance the interests of the ratepayers and the utility's shareholders to establish rates that are just and reasonable. Many witnesses who testify at local public hearings offer heartfelt and frequently heartbreaking accounts of how they are suffering from the economy in general and high utility rates in particular. As the Commission heard frequently at those hearings, many customers want the Commission to “just say no” to any proposed rate increase.

The Commission hears the public's testimony and takes it into account when deciding this or any other utility rate case. However, the Commission cannot simply “just say no” to a rate increase. The utility is entitled to charge rates sufficient to cover its costs and to yield a reasonable return on its investment. That is why the Commission took and considered extensive testimony offered by multiple parties before making the difficult decisions that are set forth and explained in this report and order.

Even if the Commission had the legal authority to "just say no" to a rate increase, doing so could cause great harm to the public. No one benefits when a utility is deprived of the ability to charge its customers a just and reasonable rate. Customers may initially be happy when the rates they pay are kept low, but as a utility's income is reduced beyond a reasonable level, it must begin to cut corners to reduce its expenses. When that happens, the reliability of the service offered by the utility will suffer. While ratepayers do not like to pay increased rates, they also do not like to sit in the cold and dark when the power goes out.

The Commission can and does consider all the testimony offered in this case, including the testimony offered by the public at the local public hearings. However, public sentiment is only part of the equation the Commission must consider when fulfilling its responsibility to establish just and reasonable rates.

2. Storm Costs/Vegetation-Infrastructure Trackers

A. Vegetation-Infrastructure:

(1) Should the Commission authorize Ameren Missouri to continue the current tracking mechanism for vegetation management and infrastructure inspections?

Findings of Fact:

Introduction:

1. Ameren Missouri's vegetation management and infrastructure inspection expense is closely associated with two Commission rules. Following extensive storm related service outages in 2006, the Commission promulgated new rules designed to compel Missouri's electric utilities to do a better job of maintaining their electric distribution systems. Those rules, entitled Electrical Corporation Infrastructure Standards[FN21] and Electrical Corporation Vegetation Management Standards and Reporting Requirements, [FN22] became effective on June 30, 2008.

FN21. Commission Rule 4 CSR 240-23.020.

FN22. Commission Rule 4 CSR 240-23.030.

2. The rules establish specific standards requiring electric utilities to inspect and replace old and damaged infrastructure, such as poles and transformers. In addition, electric utilities are required to more aggressively trim tree branches and other vegetation that encroaches on transmission lines. In promulgating the stricter standards, the Commission anticipated utilities would have to spend more money to comply. Therefore, both rules include provisions that allow a utility the means to recover the extra costs it incurs to comply with the requirements of the rule.

3. In ER-2008-0318, the Commission allowed Ameren Missouri to recover a set amount in its base rates for vegetation management and infrastructure inspection costs. However, since the rules were new, the Commission found that Ameren Missouri had too little experience to reasonably know how much it would need to spend to comply with the vegetation management and infrastructure inspection rules. Because of that uncertainty, the Commission established a two-way tracking mechanism to allow Ameren Missouri to track its vegetation management and infrastructure costs.

4. The order required Ameren Missouri to track actual expenditures around the base level. In any year in which Ameren Missouri spent below that base level, a regulatory liability would be created. In any year in which Ameren Missouri's spending exceeded the base level, a regulatory asset would be created. The regulatory assets and liabilities would then be netted against each other and would be considered in Ameren Missouri's future rate case. The tracking mechanism contained a 10 percent cap so if Ameren Missouri's expenditures exceeded the base level by more than 10 percent it could not defer those costs under the tracking mechanism, but would

need to apply for an additional accounting authority order. The Commission's order indicated that the tracking mechanism would operate until new rates were established in Ameren Missouri's next rate case.FN23

FN23.*In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service* , Report and Order, Case No. ER-2008-0318, January 27, 2009, Pages 48-49.

5. The Commission renewed the tracking mechanism in Ameren Missouri's next rate case, ER-2010-0036, finding that Ameren Missouri's costs to comply with the vegetation management and infrastructure inspection rules were still uncertain as the company had not yet completed a full four/six year vegetation management cycle on its entire system.FN24

FN24. In the Matter of Union Electric Company, d/b/a Ameren UE's Tariffs to Increase its Annual Revenues for Electric Service, Report and Order, File No. ER-2010-0036, May 28, 2010.

6. Ameren Missouri asks that the tracker be continued. Staff does not oppose the continuation of the tracker, but MIEC contends the tracker is no longer necessary and urges the Commission to end it.

Specific Findings of Fact:

7. Ameren Missouri has now been operating under the Commission's vegetation management and infrastructure inspection rules for several years. However, Ameren Missouri will not complete its first four-year cycle for vegetation management work on urban circuits under the requirements of the new rules until December 31, 2011. It will not complete the six-year cycle of work on rural circuits until December 31, 2013.FN25

FN25. Wakeman Rebuttal, Ex. 105, Page 9, Lines 19-21.

8. Ameren Missouri's actual expenditures for vegetation management and infrastructure inspection have not been extremely volatile over the last two rate cases, but they have consistently increased. Furthermore, Ameren Missouri has consistently spent more than the base amount allowed in rates.FN26 For example, the base amount allowed in rates in the last rate case was $50.4 million for vegetation management and $7.6 million for infrastructure inspections. For the twelve months ending in February 2011, the company actually spent $52.2 million on vegetation management and $7.7 million on infrastructure inspections.FN27

FN26. Meyer Surrebuttal, Ex. 401, Chart at Page 13.

FN27. Wakeman Rebuttal, Ex. 105, Page 9, Lines 7-10.

9. In a stipulation and agreement that has been approved by the Commission, the parties have agreed that the vegetation management and infrastructure actual expenses through the February 28, 2011 true-up of $52.2 million and $7.7 million will be established as the base amount allowed in rates for this case. FN28

FN28. First Nonunanimous Stipulation and Agreement - Miscellaneous Revenue Requirement Items, paragraph 20, filed on May 3, 2011, and approved by order of the Commission on June 1, 2011.

Conclusions of Law:

A. Commission Rule 4 CSR 240-23.020 establishes standards requiring electrical corporations, including Ameren Missouri, to inspect its transmission and distribution facilities as necessary to provide safe and adequate service to its customers. Specifically, 4 CSR 240-23.020(3)(A) establishes a four-year cycle for inspection of urban infrastructure and a six-year cycle for inspection of rural infrastructure.

B. Commission Rule 4 CSR 240-23.020(4) establishes a procedure by which an electric utility may recover expenses it incurs because of the rule. Specifically, that section states as follows:

In the event an electrical corporation incurs expenses as a result of this rule in excess of the costs included in current rates, the corporation may submit a request to the commission for accounting authorization to defer recognition and possible recovery of these excess expenses until the effective date of rates resulting from its next general rate case, filed after the effective date of this rule, using a tracking mechanism to record the difference between the actually incurred expenses as a result of this rule and the amount included in the corporation's rates ….

C. Commission Rule 4 CSR 240-23.030 establishes standards requiring electrical corporations, including Ameren Missouri, to trim trees and otherwise manage the growth of vegetation around its transmission and distribution facilities as necessary to provide safe and adequate service to its customers. Specifically, 4 CSR 240-23.030(9) establishes a four-year cycle for vegetation management of urban infrastructure and a six-year cycle for vegetation management of rural infrastructure. The vegetation management rule also includes a provision that would allow Ameren Missouri to ask the Commission for authority to accumulate and recover its cost of compliance in its next rate case.[FN29]

FN29. Commission Rule 4 CSR 240-23.030 (10).

Decision:

Ameren Missouri's system reliability has improved since the new rules went into effect and the Commission believes that vegetation management and infrastructure inspection is very important to that improved reliability. The Commission wants to encourage Ameren Missouri to continue to spend the money needed to improve reliability. Although Ameren Missouri now has more experience in complying with the rules, it still has not completed a single cycle on inspections for its urban or rural circuits. The Commission finds that because of that remaining uncertainty the tracker is still needed. However, as the Commission has indicated in previous rate cases, it does not intend for this tracker to become permanent. For this case, the Commission will renew the existing vegetation management and infrastructure inspection tracker.

Ameren Missouri shall establish a tracking mechanism to track future vegetation management and infrastructure costs. That tracking mechanism shall include a base level of $59.9 million ($52.2 million vegetation management + $7.7 million infrastructure = $59.9 million). Actual expenditures shall be tracked around that base level with the creation of a regulatory liability in any year where Ameren Missouri spends less than the base amount and a regulatory asset in any year where Ameren Missouri spends more than the base amount. The assets and liabilities shall be netted against each other and shall be considered in Ameren Missouri's next rate case. The tracking mechanism shall contain a ten percent cap so expenditures exceeding the base level by more than ten percent shall not be deferred under the tracking mechanism. If Ameren Missouri's vegetation management and infrastructure inspection costs exceed the ten percent cap, it may request additional accounting authority from the Commission in a separate proceeding. The tracking mechanism shall operate until the Commission establishes new rates in Ameren Missouri's next rate case.

B. Normalized Level of Non-Labor Storm Costs:

(1) How should the Commission calculate Ameren Missouri's normalized, non-labor storm costs to be included in the revenue requirement for ratemaking purposes?

(2) Should the difference between the amount of non-labor storm costs that Ameren Missouri incurred during the true-up period and the normalized level of nonlabor storm costs included in the revenue requirement for ratemaking purposes be amortized over five (5) years or should that difference be included in the normalized costs used for ratemaking purposes?

Findings of Fact:

Introduction:

10. For time to time, Ameren Missouri experiences the effects of severe storms in its service territory. Those can be severe windstorms, usually in the spring or summer, or severe ice storms in the winter. Of course, such storms are unpredictable and do not occur in any recognizable pattern. As a result, storm costs can vary greatly from year to year.

11. For example, Ameren Missouri incurred $6 million in non-labor related storm restoration costs in the nine months ending December 31, 2007, $4.8 million in 2008, $9 million in 2009, but only $38,000 in 2010. However, the company then incurred $8.1 million in such costs in February 2011.[FN30]

FN30. Ex. 151.

12. In the past, the Commission has dealt with storm costs by allowing the utility to recover an amount in rates based on a historic average of the storm costs incurred. For costs that exceed the average level of costs recovered through rates, the utility is generally allowed to accumulate and defer those costs through an accounting authority order, an AAO. The accumulated and deferred costs are then considered in the utility's next rate case. Generally, the Commission allows the utility to recover those costs amortized over a five-year period.[FN31] Using those practices, the Commission has allowed Ameren Missouri to recover every single dollar expensed for storms since April 1, 2007.[FN32]

FN31. *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, File No. ER-2010-0036, Report and Order, May 28, 2010, Page 66.

FN32. Transcript, Page 391, Lines 1-14, *see also*, Meyer Surrebuttal, Ex. 401, Page 24, Lines 1-6.

Specific Findings of Fact:

13. Ameren Missouri proposes to set the amount of storm costs it will be allowed to recover prospectively in rates by compiling a 47-month (April 2007 through February 2011) average of storm costs to obtain an average annual storm cost amount of $7,096,592. Ameren Missouri would then use this normalized amount as the amount it would recover in rates.[FN33]

FN33. Barnes Rebuttal, Ex. 103, Page 14, Lines 8-16.

14. Staff used the same 47-month period used by Ameren Missouri to calculate a normalized average annual storm cost. However, before calculating the average annual storm cost, Staff removed $8.8 million of storm costs that the Commission has previously allowed Ameren Missouri to recover by amortization.[FN34] Using its adjusted figures, Staff calculated an average annual storm cost of $4.8 million and proposes to allow Ameren Missouri to recover that amount in its rates.

FN34. Cassidy Surrebuttal, Ex. 207, Page 8, Lines 7-16. $4,857,000 was removed for the amortization in ER-2008-0318 and $3,977,675 for the amortization in ER-2010-0036.

15. MIEC also proposed to allow Ameren Missouri to recover in rates an amount based on its normalized annual storm costs. However, MIEC proposed to calculate that annual storm cost on only 23 months of costs, beginning with the start of the test year and running through the end of the true-up period (April 2009 through February 2011). On that basis, MIEC proposed to allow Ameren Missouri to recover $4.9 million.[FN35]

FN35. Meyer Surrebuttal, Ex. 401, Page 23, Lines 20-22.

16. The purpose of a normalization is to determine a reasonable expectation of what costs a utility is likely to experience in the future so that rates can be set to allow the utility a reasonable opportunity to recover those costs. For that reason, a normalization over a nearly four-year period is likely to be a better predictor of the future than is a normalization over approximately two years. That is particularly true were, as here, the company experienced a very low level of storm costs during one year of the studied period.[FN36]

FN36. Ex. 151.

17. Of course, the average over a shorter period may be a better predictor than a longer period if for some reason the costs experienced are trending in a certain direction. MIEC defended its use of the shorter period by arguing that Ameren Missouri's recent increases in vegetation management spending should have the effect of decreasing the damages that result from storms.FN37 However, MIEC did not attempt to quantify any such effect and its argument is little more than speculation. The Commission finds that MIEC's calculation of average annual storm costs based on 23 months of experience is not as reliable as the same calculation over 47 months of experience.

FN37. Transcript, Page 392, Lines 9-21.

18. Staff calculates average annual storm costs over the same 47 months of experience as Ameren Missouri, but it would exclude from that average a portion of the actual costs Ameren Missouri incurred because the Commission previously allowed the company to recover those costs by amortization.

19. As previously indicated, the purpose of a normalization is to attempt to predict the amount of expenses the company is likely to incur in the future. Staff's calculation removes from consideration a portion of the costs the company actually incurred because of past Commission decisions about how the company would be allowed to recover those costs. No matter how those costs were recovered in the past, they were still incurred. By the logic of a normalization, they are thus likely to be incurred again in the future. Therefore, the normalized amount of storm costs proposed by Staff is not a reliable indicator of the actual storm costs Ameren Missouri is likely to incur in the future.

20. The Commission finds that Ameren Missouri's calculation of average annual storm costs based on a straight 47-month average of storm costs experienced in the past is the most reliable indicator of expected future storm costs and will use that average to set future rates in this case.

21. The Commission must decide one more question. Ameren Missouri proposes that it be allowed to recover $1,037,146 through an amortization. That amount represents the difference between $8,133,738, the actual storm costs for the twelve months ending on the true-up date of February 28, 2011, and $7,096,592, the 47-month average storm costs as calculated by Ameren Missouri.FN38

FN38. Barnes Rebuttal, Ex. 103, Page 15, Lines 11-22.

22. Ameren Missouri does not explain why the 47-month average of storm costs should be the basis for determining the amount it should be allowed to amortize and that number makes no sense. Even if the 47-month average is used in this case to determine rates going forward, it bears no relationship to the amount of money Ameren Missouri was allowed to recover in rates during the period the cost was incurred. That number was set in Ameren Missouri's last rate case.

23. In Ameren Missouri's last rate case, the Commission allowed Ameren Missouri to recover $6.4 million in its cost of service for storm restoration costs.FN39 Based on that amount as well as the amount Ameren Missouri was allowed to recover in the next previous rate case, ER-2008-0318, MIEC's witness, Greg Meyer, correctly calculated that from the beginning of the test year in this case (April 1, 2009) through the end of the true-up period (February 28, 2011), Ameren Missouri has recovered $10.8 million in rates for repairs from major storms. During that same time, Ameren Missouri has incurred $9.4 million in storm costs, including the costs for the February 2011 storm preparations for which Ameren Missouri seeks an additional amortization.

FN39. *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, File No. ER-2010-0036, Report and Order, May 28, 2010, Page 68.

24/25. Based on those calculations, it is apparent that there is no basis for allowing Ameren Missouri to amortize $1,037,146 for storm costs relating to its preparation for the February 2011 ice storm.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

Ameren Missouri shall recover $7,096,592 in its rates for non-labor storm costs. Ameren Missouri shall not amortize an additional $1,037,146 for storm costs relating to its preparation for the February 2011 ice storm.

3. Sioux Scrubbers: Should the Commission allow in rate base $31 million in cost increases ($18 million in construction costs and $13 million in AFUDC) that were incurred as a result of Ameren Missouri's decision to temporarily suspend construction of the Sioux Plant Wet Flue Gas Desulfurization Project due to the Company's concerns about conditions in the financial markets during the period commencing in late 2008 and continuing into early 2009?

Findings of Fact:

Introduction:

1. Ameren Missouri seeks to add to its rate base the cost of constructing wet flue gas desulfurization units at both generating units at the company's coal-fired Sioux Plant. The wet flue gas desulfurization units are referred to as "scrubbers" by the witnesses and will be referred to as such in this report and order.

2. As their name implies, the scrubbers are designed to scrub sulfur dioxide gas (SO_2) from flue gases produced by burning coal. The wet scrubbers installed at the Sioux Plant remove SO_2 by passing the flue gas through a spray of limestone slurry solution in the scrubber reaction vessel. A chemical reaction between the limestone, air, water, and SO_2 converts the SO_2 to calcium sulfate that is removed from the scrubber and pumped in slurry form to an on-site landfill for final disposal. The scrubbers are designed to remove in excess of 95 percent of the SO_2 generated by the plant. FN40

FN40. Birk Direct, Ex. 106, Page 3, Lines 8-19.

3. Ameren Missouri installed the scrubbers at the Sioux Plant to comply with various Federal clean air rules. No party has questioned the overall prudence of the decision to install the scrubbers and that decision need not be addressed in this report and order.

4. Staff undertook an audit of the project to install the scrubbers and reported the results of that audit on February 8, 2011, as part of its direct testimony. For purposes of the audit, Ameren Missouri reported $521.8 million in charges incurred for the scrubbers project through September 30, 2010.FN41 Staff's audit recommended that $31.6 million of those costs be excluded from rate base because of Ameren Missouri's decision to slowdown construction in November 2008.FN42

FN41. Staff's Construction Audit and Prudence Review, Ex. 200, Page 1, Lines 20-21.

FN42. Staff's Construction Audit and Prudence Review, Ex. 200, Page 2, Lines 14-16.

5. Ameren Missouri challenges Staff's recommendation to disallow its costs, but does not challenge the amount of the disallowance. In other words, Staff and Ameren Missouri agree that the amount in dispute is $31.8 million.

6. Although the amount in dispute is $31.8 million, that is the amount that Staff proposes be excluded from the company's rate base. That exclusion would reduce Ameren Missouri's revenue requirement in this case by approximately $4.6 million,FN43 and would continue to reduce Ameren Missouri's revenue requirement in future rate cases as the property is depreciated.

FN43. Reconciliation, Ex. 230.

7. Staff asserts that a disallowance is necessary because of Ameren Missouri's decision to "slow down construction and ultimately shift the in-service dates to fall 2010 from fall 2009 because of this delay."FN44

FN44. Staff's Construction Audit and Prudence

Review, Ex. 200, Page 42, Lines 18-19.

Specific Findings of Fact:

8. In the fall of 2008, this country and the rest of the world was facing a financial crisis. On September 6, 2008, the United States government took over Fannie Mae and Freddie Mac. Nine days later Bank of America acquired Merrill Lynch and Lehman Brothers filed for bankruptcy. The largest bank failure in history occurred on September 26, 2008, when regulators seized Washington Mutual. The stock market plummeted throughout October and November of 2008. Because of these volatile financial conditions a credit freeze developed.[FN45]

FN45. Birdsong Rebuttal, Ex. 109, Pages 7 and 8.

9. During the credit freeze, the banking sector severely restricted the channels of credit that are needed by consumers and businesses for normal working capital and expansion needs. Banks chose to hold on to any capital they had to decrease their own leverage rather than lend money to even large, credit worthy businesses.[FN46]

FN46. Birdsong Rebuttal, Ex. 109, Page 9, Lines 4-13.

10. The electric utility industry is heavily capital-intensive. Therefore, electric utilities, including Ameren Missouri, must be concerned about their current liquidity and their ability to obtain necessary capital through their credit facilities.[FN47]

FN47. Birdsong Rebuttal, Ex. 109, Page 11, Lines 11-14.

11. Liquidity is the ability to meet expected and unexpected demands for cash at an acceptable cost at the time when needed. Electric utilities, as well as other companies, use credit facilities as a means of borrowing the cash they need to maintain liquidity.[FN48]

FN48. Birdsong Rebuttal, Ex. 109, Page 11, Lines 11-15.

12. A bank credit facility is a committed revolving bank credit line under which a company can borrow on a short-term basis, typically 30 days. Such credit facilities are syndicated by a group of bank lenders that lend by funding borrowing requests under the credit facility on a pro-rata basis.[FN49]

FN49. O'Bryan Direct, Ex. 147, Page 8, Lines 18-23.

13. In 2008, Ameren Missouri had access to a credit facility under which it could borrow up to $500 million. At the end of October 2008, Ameren Missouri had approximately $380 million of its own credit facility available. In addition, Ameren Missouri had access to part of the credit facility of its corporate parent, Ameren Corporation. In total, at that time, Ameren Missouri had access to credit facilities totaling 1.45 billion.[FN50]

FN50. Transcript, Page 515, Lines 17-25.

14. Ameren Missouri's credit facility was supported by a syndicate of 18 banks. $171 million of the total was offered by Lehman Brothers Bank and $121 million of that was no longer available after Lehman Brothers went broke. Wachovia had $156 million, Citibank had $167 million, and National City had $45 million. That means $529 million of the available credit facility was held by banks that were rumored to be in financial distress.[FN51]

FN51. Transcript, Page 516, Lines 4-21, *see also*, Birdsong Rebuttal, Ex. 109, Page 12, Lines 9-22.

15. At that time, Ameren Missouri was operating with negative free cash flow, meaning its capital expenditures were larger than the net cash flows provided by rate revenues. As a result, credit was vital to the continuation of Ameren Missouri's operations.[FN52]

FN52. Birdsong Rebuttal, Ex. 109, Page 12, Lines 4-8.

16. Very bad things happen to a utility that runs out of cash liquidity. As cash becomes short, the company will actually need more cash because suppliers will demand more payments and may require advanced payments be-

fore products are supplied. If payments are not made, the suppliers may cut off their supplies and services, such as coal and natural gas supplies, making it difficult for the utility to continue to provide electric service to its customers.FN53

FN53. Transcript, Pages 517-518, Lines 8-25, 1-9.

17. Faced with a perceived liquidity problem in October 2008, Ameren Missouri, along with Ameren Corp. and the Illinois affiliates, began looking for ways to reduce capital expenditures, primarily by focusing on reductions in larger projects that could be made quickly, had minimal impact on employees, did not impact safety, would not result in the violation of any law or regulation, did not impact the actual delivery of utility service to customers, and involved heavy use of contractors. FN54

FN54. Birdsong Rebuttal, Ex. 109, Page 15, Lines 16-20.

18. Following its review, Ameren Missouri deferred all 2009 planned generating plant outages and plant upgrades, reduced expenditures on the undergrounding portion of the Power On initiative, deferred some fleet acquisitions, and deferred certain Energy Delivery Technical Services capital projects. Along with the other deferred projects, Ameren Missouri decided to delay the Sioux scrubber project. In total, Ameren Missouri planned to reduce its capital expenditures by approximately $420 million through 2009.FN55

FN55. Birdsong Rebuttal, Ex. 109, Page 16, Lines 2-9.

19. At the time, Ameren Missouri was spending $17 million per month on the Sioux scrubber project. It planned to reduce its cash expenditures for that project to $2 million per month.FN56

FN56. Transcript, Page 443, Lines 10-12.

20. By late January, 2009, Ameren Missouri decided that its liquidity situation had improved enough to allow it to again ramp up its spending on the Sioux scrubber project.FN57

FN57. Birdsong Rebuttal, Ex. 109, Page 18, Lines 1-5.

21. The delay of the Sioux scrubber project had at least one unforeseen benefit for Ameren Missouri and its ratepayers. Ameren's installation of scrubbers at its unregulated generating plants at Duck Creek and Coffeen in Illinois, which were completed while the Sioux project was delayed, experienced quality issues with the flake glass lining system that was originally planned for the Sioux scrubbers. Because of the delay, Ameren Missouri was able to draw on that experience in Illinois to install a Stebbins glass tile lining at Sioux, thereby improving long-term reliability and decreasing maintenance costs.FN58

FN58. Birk Rebuttal, Ex. 107, Page 20, Lines 2-9.

22. Exhibit 155, which Ameren Missouri filed at the request of a Commissioner, demonstrates that it would have cost $3.47 million dollars to replace a flake glass liner at the Sioux scrubber if the Stebbins tile lining had not been used. The exhibit also demonstrates that the cumulative present worth of the revenue requirements to replace the flake glass lining range up to $33.3 million depending upon various assumptions.

23. Staff's recommendation to disallow $31.8 million of costs incurred because of the delay in completing the Sioux scrubber project is based on Staff's determination that Ameren Missouri had sufficient credit available to it under its credit facilities to avoid having to delay the project.FN59 Staff supported that recommendation by citing Ameren's issuance of common equity in September 2009 and Ameren Missouri's issuance of First Mortgage Bonds in March 2009 to show Ameren Missouri's ability to raise additional capital if it had chosen to do so.FN60

FN59. Staff's Construction Audit and Prudence Review, Ex. 200, Page 42, Lines 7-11.

FN60. Staff's Construction Audit and Prudence Review, Ex. 200, Page 42, Lines 11-15.

24. Staff never performed a liquidity analysis to determine whether Ameren Missouri had sufficient cash liquidity to avoid slowing down work on the Sioux scrubber project. Indeed, on cross-examination, Staff's witness conceded that she had no idea whether Ameren Missouri had sufficient liquidity in 2008 to continue construction and meet its daily operational needs.[FN61]

FN61. Transcript, Pages 608-609, Lines 19-25, 1-2.

25. Staff's analysis focused only on whether Ameren Missouri had access to sufficient cash and credit to continue work on the Sioux scrubber project and did not look at any other expenditures the company would also need to make at the time.[FN62]

FN62. Transcript, Page 604, Lines 7-20.

26. Ameren Missouri's issuance of additional bonds in March 2009 does not demonstrate that the company could have easily issued such bonds in November 2008, when it made the decision to slow down work on the Sioux scrubbers. By January 2009, the financial crisis had begun to ease and Ameren Missouri had taken other steps, including a reduction in its dividends, to improve its liquidity. Indeed, by that time, Ameren Missouri had made the decision to ramp up the pace of work on the scrubbers.[FN63]

FN63. Birdsong Rebuttal, Ex. 109, Page 18, Lines 1-18.

27. In October 2008, Ameren Missouri had discussions with Staff regarding the possibility of an additional bond issue by Ameren Missouri to try to improve its liquidity position. Staff told the company it would oppose that request and Ameren Missouri chose not to seek the required financing authority from the Commission at that time.[FN64] Both Staff and Ameren Missouri spent a great deal of hearing and briefing time arguing about the details of that dispute, but most of those details are classified as proprietary or highly confidential so they cannot be disclosed in this report and order. The Commission will not take the unusual step of issuing a highly confidential or proprietary version of this report and order to discuss the details of that disagreement because it is of very little relevance to the Commission's decision. As Ameren Missouri's witness indicated, around the time of that meeting, Ameren Missouri's management had already decided to slow down spending on the Sioux scrubber project and “there was never, ever any indication that by approving this financing we would not have to slow down projects, including the Sioux scrubber.”[FN65]

FN64. Murray Surrebuttal, Ex.220, Page 28, Lines 3-15.

FN65. Transcript, Page 503, Lines 5-7.

Conclusions of Law:

A. The Commission established its standard for determining the prudence of a utility's expenditures in a 1985 decision regarding Union Electric's construction of the Callaway nuclear plant. In that decision, the Commission held that a utility's expenditures are presumed to be prudently incurred, but, if some other participant in the proceeding creates a serious doubt as to the prudence of the expenditure, then the utility has the burden of dispelling those doubts and proving the questioned expenditure to have been prudent.[FN66]

FN66. *In the matter of the determination of in-service criteria for the Union Electric Company's Callaway Nuclear Plant and Callaway rate base and related issues. And In the matter of Union Electric Company of St. Louis, Missouri, for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the company.* 27 Mo. P.S.C. (N.S.) 183, 193 (1985).

B. The 1985 Union Electric decision also established the standard by which the prudence of a utility's decision would be evaluated when it said:

In reviewing UE's management of the Callaway project, the Commission will not rely on hindsight. The Commission will assess management decisions at the time they were made and ask the question, ‘Given all the surrounding circumstances existing at the time, did management use due diligence to address all relevant factors and information known or available to it when it assessed the situation?'[FN67]

FN67.*In the matter of the determination of in-service criteria for the Union Electric Company's Callaway Nuclear Plant and Callaway rate base and related issues. And In the matter of Union Electric Company of St. Louis, Missouri, for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the company*. 27 Mo. P.S.C. (N.S.) 183, 194 (1985).

C. The Commission's use of that prudence standard is consistent with judicial precedent[FN68] and has been accepted and applied by reviewing courts.[FN69]

FN68.“Good faith is to be presumed on the part of the managers of a business. In the absence of a showing of inefficiency or improvidence, a court will not substitute its judgment for theirs as to the measure of a prudent outlay.” *West Ohio Gas Co. v. Pub. Util. Com'n of Ohio*, 294 U.S. 63, 72, 55 S.Ct. 316, 321 (1935)

FN69.*For example see, State ex rel. Assoc. Natural Gas Co. v. Public Serv. Com'n, 954 S.W.2d 520 (Mo. App. W.D. 1997).*

D. In order to disallow a utility's recovery of costs from its ratepayers, a regulatory agency must find both that the utility acted imprudently and that such imprudence resulted in harm to the utility's ratepayers.[FN70]

FN70.*State ex rel. Assoc. Natural Gas Co. v. Public Serv. Com'n, 954 S.W.2d 520 (Mo. App. W.D. 1997).*

E. Applying the prudence standard as it has been defined by the Commission, the first step is to determine whether any party has raised a serious doubt about the prudence of Ameren Missouri's decision to slow down the Sioux scrubber project to preserve cash in the face of the global economic crisis of 2008. That raises the question of what is a “serious doubt?”

F. In its reply brief, Staff suggests that the presumption of prudence is only a matter of convenience designed to focus attention on those items that are subject to challenge by any party on grounds that are reasonable on their face.[FN71] If as Staff suggests, the presumption of prudence is only a matter of convenience, then it could be overcome by a simple statement by a party that it wants to challenge a particular decision on some reasonable basis without presenting a shred of evidence to show that the utility did anything wrong.

FN71. Staff's Reply Brief, Page 4.

G. Staff's suggestion is not correct, the presumption of prudence is not just a matter of convenience. The United States Supreme Court in the *West Ohio Gas* case indicated that the presumption of prudence is real and is not overcome absent a showing of inefficiency or improvidence.[FN72]That is what “serious doubt” means. By statute, the utility has the burden of proving that its proposed rates are just and reasonable. However, before the presumption of prudence is overcome, the challenging party must present sufficient evidence to create a serious doubt about a decision of the utility. Staff failed to create a serious doubt in this case.

FN72.*West Ohio Gas Co. v. Pub. Util. Com'n of Ohio*, 294 U.S. 63, 72, 55 S.Ct. 316, 321 (1935)

Decision:

Staff's recommendation to disallow $31.8 million of costs incurred because of the delay in completing the Sioux scrubber project is based on Staff's determination that Ameren Missouri had sufficient credit available to it under its credit facilities to avoid having to delay the project. But Staff never undertook any sort of liquidity analysis to determine whether Ameren Missouri actually had reliable access to sufficient cash to continue to pay $17 million per month for the Sioux scrubber project while also meeting all its other needs and contingencies. Instead, Staff seems to have naively assumed that if Ameren Missouri had $31.8 million in available cash or credit in November 2008 it should have used those funds to continue forward with the Sioux scrubber project without taking into account the very real uncertainties facing the company because of the financial crisis.

Even assuming that Staff was able to raise a serious doubt about the prudence of Ameren Missouri's decision to slow down work on the Sioux scrubbers at the height of the global financial crisis, Ameren Missouri presented more than enough evidence to dispel those doubts and to prove that the questioned expenditure was prudent. Ameren Missouri demonstrated that measured by what it knew at the time, without the benefit of hindsight, it was justifiably concerned that it faced the potentially cataclysmic danger of running out of liquidity. Under those circumstances, the decision to slow down the Sioux scrubber project for a few months was a prudent act.

Furthermore, there is little indication that Ameren Missouri's customers were actually harmed by Ameren Missouri's decision to slow down work on the Sioux scrubber project. Certain costs did increase because of the delay as Staff indicates, but the delay also gave the company an opportunity to learn from mistakes made in the construction of similar scrubbers at other power plants. In particular, Ameren Missouri learned from experience that the flake glass lining proposed for use in the Sioux scrubber was not optimal and instead installed a Stebbins glass tile lining that saved the company and its ratepayers up to $33.3 million, offsetting the additional costs associated with the delay.

In summary, Staff failed to raise a serious doubt about the prudence of Ameren Missouri's decision to slow down work on the Sioux scrubber project. Even if it is assumed that Staff was able to raise a serious doubt about the prudence of those expenditures, Ameren Missouri dispelled those doubts and proved that those expenditures were prudent. Finally, savings that were made possible by the delay offset any costs to ratepayers that resulted from Ameren Missouri's decision to slow down the Sioux scrubber project. On those bases, the Commission will reject Staff's proposed $31.8 million disallowance.

4. Energy Efficiency/Demand Side Management (DSM):

A. Is Ameren Missouri in compliance with the Missouri Energy Efficiency Investment Act (MEEIA) regardless of whether or not proposed rules under the law are effective?

(1) What DSM programs should Ameren Missouri continue and/or implement, and at what annual expenditure level; and

(2) Should Ameren Missouri continue to ramp up its demand side management programs to pursue all cost-effective demand side savings?

B. Does Ameren Missouri's request for demand-side management programs' cost recovery in this case comply with MEEIA requirements?

(1) Should the Commission approve a cost recovery mechanism for Ameren Missouri DSM programs as part of this case? If so,

(a) Over what period should DSM program costs incurred after December 31, 2010, be amortized?

(b) Should the mechanism include an adjustment of kWh billing determinants?

(c) How much should the Commission reduce the billing determinants?

(d) If billing units are adjusted for demand side savings, how should the NBFC rates be calculated?

Findings of Fact:

Introduction:

1. Energy Efficiency and Demand Side Management (DSM) programs are designed to encourage an electric utility's customers to reduce their use of electricity. In recent years, Ameren Missouri has undertaken a number of residential and business energy efficiency and DSM programs. The particular programs are listed and de-

scribed in the direct testimony of MDNR's witness Laura Wolfe[FN73]

FN73. Wolfe Direct, Ex.800, Pages 3-4.

2. Ameren Missouri has not submitted those programs to the Commission for approval under the Missouri Energy Efficiency Investment Act.[FN74]

FN74.Section 393.1075, RSMo (Supp. 2010).

3. Ameren Missouri has spent significant amounts of money to support those energy efficiency and DSM programs in recent years. Those expenditures rose from $13.5 million in 2008 and 2009, to $23 million in 2010, to an anticipated spending level of $33 million in 2011.[FN75] All parties agree that those energy efficiency and DSM initiatives have been effective in reducing energy usage and would like to see them continue. However, Ameren Missouri's electric energy efficiency programs offered under the existing tariffs end on September 30, 2011,[FN76] and Ameren Missouri may significantly reduce its energy efficiency expenditures in the future.[FN77]

FN75. Mark Surrebuttal, Ex. 111, Page 4, Lines 4-6.

FN76. Laurent Surrebuttal, Ex. 113, Page 4, Lines 12-15.

FN77. Mark Rebuttal, Ex. 110, Page 8, Lines 7-12.

4. Ameren Missouri indicates it would like to continue its current slate of programs at current funding levels, but is willing to do so only if the Commission approves its proposals to establish a mechanism to allow it to recover the revenue it will lose because of reduced sales of electricity as customers reduce their use of electricity as a result of the energy efficiency programs.[FN78]

FN78. Laurent Surrebuttal, Ex. 113, Page 4, Lines 16-21.

5. Ameren Missouri describes the problem of declining sales as the throughput disincentive and the issue is about how the Commission should address that disincentive.

Specific Findings of Fact:

6. The throughput disincentive results from the traditional regulated utility business model in which a utility earns revenues by selling electricity. Under that model, the more electricity it sells, the more revenue the utility earns to cover its fixed costs and to provide a profit for its shareholders.[FN79] Energy efficiency programs are designed to reduce electricity sales. Thus, by implementing energy efficiency programs, the utility is knowingly causing financial harm to itself. Understandably, utility companies are reluctant to reduce their earnings, resulting in a strong incentive for the company to spend as little as possible on energy efficiency programs.[FN80]

FN79. Davis Rebuttal, Ex. 115, Page 1, Lines 20-23.

FN80. Davis Rebuttal, Ex. 115, Page 3, Lines 11-13.

7. The throughput disincentive has a real effect on Ameren Missouri's earnings. Ameren Missouri estimated that if it were to continue to spend $25 million per year on energy efficiency over the next two years without a rate case, it would lose about $53 million in additional revenue.[FN81]

FN81. Davis Rebuttal, Ex. 115, Page 5, Lines 1-5.

8. Advocates for energy efficiency are of course aware of this disincentive and search for the means to realign the utility's interests to more closely match the goal of increasing energy efficiency to reduce the use of electricity. In Missouri, the Missouri Energy Efficiency Investment Act (MEEIA) makes that realignment the policy of this state.[FN82]

FN82.Section 393.0175, RSMo (Supp. 2010).

9. Ameren Missouri asks the Commission to address the throughput disincentive in this case by implementing an

adjustment to decrease the billing units used to set rates in anticipation of reduced sales resulting from energy efficiency programs.FN83 However, Ameren Missouri did not propose its billing unit adjustment plan until it filed the rebuttal testimony of William Davis on March 25, 2011.

FN83. Davis Rebuttal, Ex. 115, Pages 6-7.

10. Ameren Missouri's proposed billing unit adjustment is a new and novel idea that to the knowledge of the Ameren Missouri witness who proposed it, has never been tried anywhere else in the country.FN84 Because Ameren Missouri did not file its “new and novel idea until its rebuttal testimony, the other parties had a very limited amount of time to evaluate that idea before filing their surrebuttal testimony two weeks later.

FN84. Transcript, Page 1911, Lines 1-12.

11. The proposed billing rate unit adjustment would have the effect of increasing rates by allowing the company to recover its revenue requirement over a smaller number of units. For example if the revenue requirement is $100 and the normalized, annualized billing unit is 1,000 kWh, then the rate would be $0.10 per kWh ($100 divided by 1,000 kWh) and the company would collect its $100 revenue requirement after selling 1,000 kWh of electricity. If in the same example the billing units were reduced to 800 kWh, the resulting rate would be $0.125 per kWh and the company would collect $125 when it sells 1,000 kWh of electricity.FN85 Staying with the example, Ameren Missouri's justification for this adjustment is that because of energy efficiency programs it anticipates selling only 800 kWh, meaning it will in fact collect only its $100 revenue requirement.

FN85. Mantle Supplemental Testimony, Ex. 247, Page 2, Lines 8-20.

12. Despite Ameren Missouri's protests to the contrary, the proposed billing units adjustment is a mechanism that attempts to compensate the company for lost revenue. It just tries to accomplish that compensation before the revenue is lost, which is a distinction without meaning. As Ameren Missouri's witness, William Davis, indicated in the following exchange at the hearing:

Q. Isn't the whole purpose of the billing unit adjustment to recover future lost sales revenue?

A. Associated with fixed costs, yes, and a reduction in sales associated with our energy efficiency programs. FN86

FN86. Transcript, Page 1878, Lines 5-9.

13. As a lost revenue recovery mechanism, Ameren Missouri's proposed lost revenue mechanism must comply with the requirements of the Commission's rule regarding Demand-Side Programs Investment Mechanisms.FN87 The Commission will discuss the application of that rule in its Conclusions of Law regarding this issue.

FN87.4 CSR 240-20.093, *See Also*, Rogers Supplemental Testimony, Ex. 246, Page 2, Lines 21-25.

14. Most significantly, the proposed billing units adjustment does not eliminate the throughput disincentive. It would guarantee the company a greater recovery, but the company would continue to benefit from increases in energy sales and suffer a loss of income when sales drop just as it would without the adjustment.FN88 In other words, despite the use of the billing units adjustment, Ameren Missouri would still have just as much incentive to maximize its sales of electricity and minimize energy efficiency programs.

FN88. Rogers Surrebuttal, Ex. 222, Page 14, Lines 6-10.

15. William Davis, Ameren Missouri's witness who proposed the billing units adjustment, admitted on the stand that his plan did not decrease the company incentive to increase sales. His only defense was to indicate that he was not aware of any plans by Ameren Missouri to implement any programs to increase its sales.FN89

FN89. Transcript, Page 1878, Lines 10-21.

16. In effect, Ameren Missouri's proposed billing units adjustment relies on the willingness of the Commission

and ratepayers to hand the company extra money while trusting to the good intentions of the company to avoid acting in compliance with its throughput incentive by maximizing sales while minimizing energy efficiency efforts.

17. The Commission finds that Ameren Missouri's proposed billing units adjustment is a hastily proposed and ill-conceived lost revenue recovery mechanism that the Commission is not willing to adopt in its present form.

18. Aside from consideration of the proposed billing units adjustment, there is one other matter related to energy efficiency and DSM programs that the Commission needs to address. Currently, between rate cases, Ameren Missouri is allowed to book its direct costs incurred while implementing energy efficiency and DSM programs to a regulatory asset. In the rate case, the amount in the regulatory asset is added to the company's rate base and is amortized over a six-year period. That procedure was established by a stipulation and agreement in Ameren Missouri's last rate case.[FN90]

FN90. Davis Direct, Ex. 114, Pages 3-4, Lines 19-24, 1-5.

19. Ameren Missouri initially proposed that the amortization period be decreased from six years to three.[FN91] Subsequently, Ameren Missouri dropped its proposal to decrease the amortization period to concentrate on dealing with the throughput disincentive.[FN92] MDNR continues to support at least a decreased amortization period and suggests that such expenses should be expensed and recovered immediately instead of amortized.[FN93] MIEC goes the other direction and argues the amortization period should be increased to ten years.[FN94]

FN91. Davis Direct, Ex. 114, Page 5, Lines 10-13.

FN92. Transcript, Page 1867, Lines 15-22.

FN93. Wolfe Direct, Ex. 800, Page 11, Lines 13-16.

FN94. Brubaker Direct, Ex. 403, Page 14, Lines 12-18.

20. MIEC's argument for a ten-year amortization period is that demand-side resources are to be treated comparably with supply-side resources. A utility recovers its supply-side costs through depreciation over the useful life of the asset. For a demand-side asset, the equivalent asset is a “regulatory asset” that is recovered through an amortization. Ameren Missouri would recover the cost of supply-side assets that are displaced by demand-side resources through depreciation over twelve years. On that basis, MIEC's witness argues Ameren Missouri should recover the cost of its demand-side resources over at least a ten-year period.[FN95]

FN95. Brubaker Direct, Ex. 403, Pages 11-14.

21. As Ameren Missouri's witness explained, there is no objective basis for the six-year amortization period currently in use. It was simply the product of negotiations in Ameren Missouri's last rate case.[FN96] Similarly, there is no objective basis to return to a ten-year amortization period other than it was used before the six-year amortization period was instituted. MIEC comparison of the amortization period to the depreciation period of displaced supply-side resources is not convincing. The real reason to stay with a six-year amortization period is to continue to allow Ameren Missouri a reasonable incentive to make demand-side expenditures.

FN96. Davis Direct, Ex. 114, Page 4, Lines 10-12.

22. A lengthy amortization period for Ameren Missouri's DSM costs would provide a strong disincentive for the utility to incur those costs and would be inconsistent with the policy established by MEEIA that favor timely recovery cost recovery for utilities. The Commission does not want to send that signal and will not alter the current six-year amortization period.

Conclusions of Law:

A. The Missouri Energy Efficiency Investment Act (MEEIA) provides in part as follows:
3. It shall be the policy of the state to value demand-

side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs. In support of this policy the commission shall:
(1) Provide timely cost recovery for utilities;
(2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and
(3) Provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.[FN97]

FN97.393.1075.3, RSMo (Supp. 2010).

In this section, the legislature has set out the policy considerations that must guide the Commission in reaching its decision on this issue.

B. The Commission has established rules to implement MEEIA. 4 CSR 240-20.093 establishes specific requirements for the creation of Demand-Side Programs Investment Mechanisms. 4 CSR 240-20.094 establishes procedures for filing and processing applications for approval, modification, and discontinuance of electric utility demand-side programs.

C. Section 4 of MEEIA requires the Commission to permit electric corporations to implement “commission approved demand-side programs.” That section also provides “[R]ecovery for such programs shall not be permitted unless the programs are approved by the commission, …” Ameren Missouri has not submitted an application pursuant to MEEIA or the MEEIA rules for approval of any of its demand-side programs.[FN98]

FN98. Rogers Surrebuttal, Ex. 222, Page 6, Lines 36-37.

D. Commission Rule 4 CSR 240-20.093(1)(Y) defines lost revenue as:
the net reduction in utility retail revenue, … that occurs when utility demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 cause a drop in net system retail kWh delivered to jurisdictional customers below the level used to set the electricity rates.

By that definition, lost revenue would include only revenue losses that exceed net gains in sales from other sources. That definition is inconsistent with Ameren Missouri's billing units adjustment proposal that would allow the company to recover for any potential lost revenue, even if its net revenue was rising from another source.

E. The rule's definition of lost revenue goes on to say:
Lost revenues are only those net revenues lost due to energy and demand savings from utility demand-side programs approved by the commission in accordance with 4 CSR 240-094 Demand-Side Programs and measured and verified through EM&V. (evaluation, measurement and verification)

That definition once again allows recovery only for demand-side programs approved by the Commission. It also means that recovery is not allowed until the program has been evaluated to “estimate and/or verify the estimated actual energy and demand savings, utility lost revenue, cost-effectiveness, and other effects from demand-side programs.”[FN99] Ameren Missouri's billing units adjustment proposal would not comply with either aspect of the definition and could allow Ameren Missouri to recover revenue in the future that is in excess of the rule's definition of lost revenue.

FN99.4 CSR 240-20.093(1)(V), the definition of evaluation, measurement, and verification.

F. Section 393.1075.13 of MEEIA requires that “[c]harges attributable to demand-side programs under this section shall be clearly shown as a separate line item on bills to the electrical corporation's customers.”Ameren Missouri's billing units adjustment proposal would raise customer rates without disclosing that increase to customers and would therefore be inconsistent with MEEIA.

G. Ameren Missouri has indicated its intention to significantly reduce its spending on energy efficiency and DSM programs if the Commission does not approve its billing units adjustment proposal. Some parties suggest that the Commission simply order Ameren Missouri to continue spending for those programs at their current levels. However, the Commission, while it has the power to regulate Ameren Missouri, does not have the power to take over management of the utility.FN100 MEEIA does not contain any language that requires utilities, or allows the Commission to require utilities, to spend any particular level of dollars on energy efficiency, or to achieve any particular amount of MWh savings through energy efficiency. Therefore, the Commission cannot order Ameren Missouri to continue spending money on energy efficiency and DSM programs.

FN100.*State ex rel. Harline v. Public Serv. Com'n*, 343 S.W.2d 177,182 (Mo. App. 1960).

H. Ameren Missouri indicates that it wants to continue to offer energy efficiency and DSM programs. Once Ameren Missouri files an application for approval of its programs under MEEIA, perhaps a cost recovery mechanism satisfactory to Ameren Missouri and its ratepayers can be worked out. But the Commission cannot bridge that gap between this rate case and the company's MEEIA application by approving a cost recovery mechanism that is wholly inconsistent with MEEIA and the implementing regulations. Therefore, the Commission must reject Ameren Missouri's billing units adjustment proposal.

Decision:

For the reasons set forth in its findings of fact and conclusions of law, the Commission rejects Ameren Missouri's billing units adjustment proposal. The Commission also directs that DSM program costs incurred after December 31, 2010, shall continue to be amortized over a period of six years.

C. Should a portion of the low-income weatherization program funds be utilized to engage an independent third party to evaluate the program?

Findings of Fact:

Introduction:

1. Ameren Missouri currently funds a low-income weatherization program at a rate of $1.2 million per year. MDNR asked that the company continue to fund the program at that level.FN101 Ameren Missouri agreed.FN102

FN101. Wolfe Direct, Ex. 800, Page 5, Lines 1-2.

FN102. Laurent Rebuttal, Ex. 112, Page 8, Lines 6-8.

2. Following the evidentiary hearing, on May 18, 2011, Ameren Missouri and MDNR filed a nonunanimous stipulation and agreement by which the company agreed to continue funding the low-income weatherization program at $1.2 million per year. The signatories also agreed that Ameren Missouri would contract with an independent third party contractor to conduct both a process and impact evaluation of the low-income weatherization program every two years. The independent evaluation was to be funded by withholding up to $60,000 per year from Ameren Missouri's payment to the program.

3. Public Counsel filed a written objection to the nonunanimous stipulation and agreement on May 25. Public Counsel objected that the recurring evaluation would consume money that would otherwise be used to provide weatherization services.

4. Because the nonunanimous stipulation and agreement was objected to, it becomes just a joint position of the signatory parties.

Specific Findings of Fact:

5. As Ameren Missouri's witness indicates, the low-income weatherization program should have more transparent reporting and should be evaluated as are other energy efficiency programs.FN103

FN103. Laurent Rebuttal, Ex. 112, Page 8, Lines 8-10.

6. The impact evaluation contemplated by Ameren Missouri and MDNR's joint position would determine the energy and demand savings of the program. Process evaluation would assess the effectiveness of the program implementation processes.FN104

FN104. Laurent Rebuttal, Ex. 112, Page 4, FN 1.

6. Setting aside $60,000 per year to evaluate a multi-million dollar program is reasonable and prudent.

Conclusions of Law:

A. Commission Rule 4 CSR 240-2.115(2)(D) provides that a nonunanimous stipulation and agreement to which an objection is made is to be treated as a joint position of the signatory parties, except that no party is bound by the agreement.

B. The approach the Commission must take when considering a nonunanimous stipulation and agreement to which an objection is made is further described in a 1982 decision of the Missouri Court of Appeals. In *State ex rel. Fischer v. Public Service Commission,* FN105 the Court held that when considering a nonunanimous stipulation and agreement the Commission must recognize all statutory requirements, including the right to be heard and to introduce evidence. Furthermore, the Commission's decision must be in writing and must include adequate findings of fact.

FN105.645 S.W.2d 39 (Mo. App. W.D. 1982)

Decision:

Ameren Missouri shall continue its annual payments of $1,200,000 to the Environmental Improvement and Energy Resources Authority ("EIERA") for the purposes of funding weatherization of homes owned by qualified low-income Ameren Missouri electric customers ("Low Income Weatherization Program"), less an amount set aside for evaluation of the Low Income Weatherization Program.

Ameren Missouri shall contract with an independent third party contractor to conduct both a process and impact evaluation ("evaluation") of the Low Income Weatherization program in Ameren Missouri's service territory as follows:
A. The first evaluation under this agreement will be completed by April 30, 2012.
B. The first evaluation will cover the time period of January 1, 2010 through December 31, 2011.
C. Evaluations will be conducted every two years thereafter.

The evaluation is to be funded from Ameren Missouri's withholding from Ameren Missouri's annual payment to EIERA of a maximum amount of $60,000 annually. This is intended to provide $120,000 as the maximum funding for each evaluation. In the event an evaluation costs less than $120,000, the remaining funds will serve to reduce the next annual $60,000 withholding.

5. Taum Sauk: What amount, if any, of Ameren Missouri's investment related to the reconstruction of Taum Sauk should be included in rate base for ratemaking purposes?

Findings of Fact:

Introduction:

1. The Taum Sauk plant is a pumped storage facility located in Reynolds County, Missouri. It consists of an upper reservoir located on the top of a mountain, a shaft and tunnel conduit, two 220-megawatt pump-turbine units, and a lower reservoir. When the cost of electricity to run the pumps is low, water is pumped from the lower reservoir to the upper reservoir. When demand for electricity and the resulting price of that electricity is high, the water in the upper reservoir is allowed to drain down through the tunnel conduit to turn the turbines to generate electricity. When the price of electricity again drops, the water is pumped back up and the cycle is repeated.FN106

FN106. Birk Direct, Ex. 106, Page 23, Lines 3-22.

2. In the early morning of December 14, 2005, a portion

of the parapet wall and the northwest corner of the dike around the upper reservoir breached, causing an uncontrolled, rapid release of water down the mountain. The flood swept through Johnson's Shut-ins State Park and Campground, devastating the park and washing away the home of the park superintendent. Fortunately, no one was killed.FN107

FN107. Birk Direct, Ex. 106, Page 24, Lines 17-23.

3. The Commission's Staff investigated the failure of the upper reservoir and issued a report in 2007. That report concluded:

[t]he Upper Reservoir at the Taum Sauk Pumped Storage Project breached on the early morning of December 14, 2005, because the reservoir overtopped when more water was pumped into the Upper Reservoir than it could hold. The overtopping occurred because (1) the plant was customarily operated with an insufficient margin of safety, (2) the water level sensors were unreliable because they had broken free from their anchoring system, and (3) the emergency back-up sensors, intended to prevent the exact chain of events that in fact occurred, had been improperly set too high. The breach was entirely avoidable in that the Company knew for over two months that the water level sensors were unreliable, as they had broken free from their anchoring system, but unaccountably failed to make repairs. The failure was a management failure in that Ameren had organized the operation of its plants and the performance of maintenance, repair and improvement activities at its plants in such a way that overall direction was lacking and crucial information was not shared.FN108

FN108.*In the Matter of an Investigation Into an Incident in December 2005 at the Taum Sauk Pumped Storage Project Owned and Operated by the Union Electric Company, doing business as AmerenUE*, Case No. ES-2007-0474, Staff's Initial Incident Report, October 24, 2007, Pages 4-5.

Based on its findings, Staff recommended:

[t]hat any and all costs, direct and indirect, associated with the Taum Sauk incident be excluded from rates on an ongoing basis. This includes, but is not limited to, the exclusion of rebuilding costs and treating the facility as though its capacity is available for dispatch modeling.FN109

FN109.*In the Matter of an Investigation Into an Incident in December 2005 at the Taum Sauk Pumped Storage Project Owned and Operated by the Union Electric Company, doing business as AmerenUE*, Case No. ES-2007-0474, Staff's Initial Incident Report, October 24, 2007, Pages 82.

4. Ameren Missouri has accepted full responsibility for the failure of the upper reservoir.FN110 Up until now, the company's ratepayers have not been asked to pay any of the cost of cleaning up after the breach or the cost of rebuilding the upper reservoir.

FN110. Transcript, Page 209, Lines 11-14.

5. Ameren Missouri has now rebuilt the upper reservoir and the Taum Sauk unit is once again producing electricity. In this case, it is asking the Commission to include $89 million in its rate base for construction of “enhancements” to the upper reservoir because of the rebuild.FN111 The $89 million figure was derived by subtracting the $400 million in insurance proceeds received by Ameren Missouri from the $489 million total cost to rebuild the upper reservoir.FN112

FN111. The inclusion of $89 million in rate base does not mean that Ameren Missouri's revenue requirement would increase by that amount in this case. Ameren Missouri would include that amount in its rate base, which it will recover through depreciation over the life of the property. The impact on revenue requirement for this case would be approximately $10.4 million if Ameren Missouri is allowed to include the entire $89 million in rate base.

FN112. Transcript, Page 881, Lines 10-13.

6. Although Ameren Missouri's proposal would allow it

to recover all rebuilding costs not covered by insurance, it has absorbed approximately $94 million in insurance deductibles, fines, lost energy and capacity, and other expenses resulting from the collapse for which it has not sought recovery from ratepayers.FN113

FN113. Birk Direct, Ex. 106, Page 39, lines 1-15, *see also*, Transcript, Page 432.

Specific Findings of Fact:

7. The Commission's Staff conducted an audit of Ameren Missouri's rebuild of the Taum Sauk upper reservoir and reported the results of that audit in this case.FN114 Staff did not recommend any disallowances as the result of its audit. That means that except for Ameren Missouri's responsibility for the breach of the reservoir in 2005, no party has questioned the specific costs of the rebuild project and those costs are not otherwise at issue. Instead, the question before the Commission is whether Ameren Missouri should be allowed to recover all, or any part of those cost due to its imprudence in causing the failure of the upper reservoir in 2005.

FN114. Staff's Construction Audit and Prudence Review of Taum Sauk Project for Costs Reported as of October 31, 2010. Ex. 203.

8. Following the failure of the upper reservoir, Ameren Missouri was sued by the State of Missouri in the Circuit Court of Reynolds County. That lawsuit resulted in the entry of a Consent Judgment.FN115 Signed by Ameren Missouri and by Missouri's Attorney General on behalf of the State of Missouri, including the Missouri Department of Natural Resources, the Missouri Clean Water Commission, and the Missouri Conservation Commission, that Consent Judgment required Ameren Missouri to pay damages and to rebuild the upper reservoir.

FN115. Ex. 157.

9. The Commission was not a party to the Consent Agreement and is not bound by its terms.

10. The Consent Agreement includes the following provision under the heading “Ratepayer Protection”:

AmerenUE acknowledges that it will not attempt to recover from ratepayers in any rate increase any in-kind or monetary payments to the State Parties required by this Consent Judgment or construction cost incurred in the reconstruction of the Upper Reservoir Dam (expressly excluding, however, “allowed costs,” which shall mean only enhancements, costs incurred due to circumstances or conditions that are currently not reasonably foreseeable and costs that would have been incurred absent the Occurrence as allowed by law), and further acknowledges the audit powers of the Missouri Public Service Commission to ensure that no such recovery is pursued. In the event that Ameren intends to seek recovery for allowed costs, it shall notify the State Parties in writing at least seven (7) business days in advance of its initial application for the recovery of these costs. If AmerenUE fails to provide the required notice, it shall forfeit whatever legal right it has to seek such recovery. (Emphasis added)FN116

FN116. Ex. 157.

11. Ameren Missouri provided the notice to the State Parties required by the provision on August 16, 2010. FN117 None of the named state parties has objected to Ameren Missouri's attempt to recover the described costs.

FN117. Ex. 158.

12. The Missouri Department of Natural Resources is a party to this case, but has not opposed Ameren Missouri's attempt to recover the costs. MDNR is represented by the Missouri Attorney General's office. When asked about the State's position regarding the attempt to recover the costs, counsel for MDNR stated that she was authorized to say that “the Attorney General's office did review Ameren's request for reimbursement after this case was filed and we have no evidence to believe that the request is inconsistent with or in violation of the consent judgment on record in Reynolds County.” FN118

FN118. Transcript, Page 2124, Lines 10-15.

13. Ameren Missouri asserts that the costs it seeks to recover are “allowed costs” under two provisions of the Consent Judgment. First it claims those costs paid for “enhancements”, and second it claims those costs would have been incurred even if the reservoir had not collapsed. The Commission will address the second argument first.

14. Ameren Missouri contends all $89 million in rebuild costs not covered by insurance should be recoverable because it would have had to rebuild the upper reservoir soon even if it had not collapsed in 2005.

15. Paul Rizzo, a civil engineer, offered testimony in that regard on behalf of Ameren Missouri. Ameren Missouri hired him after the collapse of the upper reservoir to perform a forensic investigation and root cause analysis regarding the collapse. He concluded that the reservoir collapsed due to over-pumping associated with faulty instrument control systems coupled with substandard construction and inadequate design.[FN119] Subsequently, his firm served as construction manager for the rebuild of the upper reservoir.[FN120]

FN119. Rizzo Direct, Ex. 117, Page 2, Lines 22-25.

FN120. Transcript, Page 770, Lines 17-22.

16. The Taum Sauk plant is regulated by the FERC and has been subject to a major independent dam safety inspection every five years beginning in 1985. The old Taum Sauk plant passed its last inspection in 2003.[FN121]

FN121. Rizzo Direct, Ex. 117, Page 17, Lines 22-26.

17. Beginning in 2003, the FERC began using a new, more rigorous dam safety inspection process known as the Potential Failure Modes Analysis (PFMA) Program. Taum Sauk would have been inspected under that more rigorous process in 2008.[FN122]

FN122. Rizzo Direct, Ex. 117, Page 18, Lines 1-14.

18. Rizzo testified that if Taum Sauk had been inspected under the PFMA program, that inspection would have revealed that the old dam used the parapet wall for water retention in violation of modern safety standards,[FN123] the dam did not meet modern seismic standards and could not withstand a significant earthquake,[FN124] and due to excessive leakage from the old reservoir, there were significant voids under the concrete foundation.[FN125] Most fundamentally, the foundation of the old upper reservoir was completely inadequate. In part that inadequacy was due to deficiencies in the way the dam was originally designed and in part because the construction of the dam did not follow the design requirements.[FN126]

FN123. Rizzo Direct, Ex. 117, Pages 19-20.

FN124. Rizzo Direct, Ex. 117, Pages 29-30.

FN125. Rizzo Direct, Ex. 117, Pages 30-32,

FN126. Rizzo Direct, Ex. 117, Pages 20-29.

19. In Rizzo's opinion, after seeing the results of the PFMA inspection, the FERC would have required a complete rebuild of the facility, like the rebuild that Ameren Missouri actually did, to fully address the safety risks he identified.[FN127]

FN127. Rizzo Direct, Ex. 117, Page 32, Lines 11-25.

20. Ameren Missouri argues that because the FERC would have required it to rebuild the dam in a few years anyway, all the reconstruction costs are “costs that would have been incurred absent the occurrence” and thus qualify as “allowed costs” under the Consent Agreement. The Commission does not accept that argument.

21. First, Paul Rizzo appears to be a very good civil engineer and he offered very credible evidence about the condition of the old dam, why it collapsed, and why it should have failed a FERC inspection in 2008. Of course, those problems were also present in 2003 when

the Taum Sauk reservoir passed a FERC inspection. At least some of the deficiencies should have been apparent to an inspector even without the enhanced inspection required by the new PFMA process. For example, an inspector should have been able to tell that the parapet walls were being used to retain water without an extensive inspection.

22. The problem is that Rizzo is a civil engineer, not a FERC bureaucrat. While he can say with great credibility that the old reservoir should have failed a FERC inspection in 2008, he cannot say with certainty what FERC would have done with the results of that inspection. As a result, the Commission cannot conclude that the upper reservoir would have had to be rebuilt even if it had not collapsed and therefore cannot conclude that the costs are "allowed costs" because they "would have been incurred absent the Occurrence."

23. The second reason the Commission will not accept the "reservoir would have had to be rebuilt anyway" argument has nothing to do with the language of the Consent Judgment. Rizzo's testimony reveals that the upper reservoir was very poorly constructed even by 1963 standards. In particular, the foundation was deficient because smaller soil particles, known as "fines" were allowed to remain in the rockfill mass comprising the dam. The people responsible for construction of the dam knew about the "fines" problem at the time, but did not fix the problem.[FN128] Furthermore, the design called for foundation rock to be cleaned of organic material, top soil, residual soil, and weathered rock with a bulldozer such that no more than 2 inches of such material was left in place. However, as much as 18 inches of low strength material, including top soil and vegetation was left in place under the foundation.[FN129] Union Electric Company, Ameren Missouri's parent company, was ultimately responsible for the construction of the upper reservoir.

FN128. Rizzo Direct, Ex. 117, Pages 27-29.

FN129. Rizzo Direct, Ex. 117, Page 21, Lines 9-13.

24. Essentially then, Ameren Missouri's "the reservoir would have had to be rebuilt anyway" argument is that not only did the company operate the reservoir recklessly and imprudently in 2005, it also constructed it poorly fifty years ago. That is not a reasonable basis to allow the company to pass the uninsured portion of the costs of the rebuild on to its ratepayers.

25. Moving on to the other argument about the meaning of the Consent Judgment's exception, the Consent Judgment does not define the term "enhancement" in its definition of allowed costs. Furthermore, "enhancement" is not a term in general use within the field of utility regulation.

26. Ameren Missouri and Staff further divide the concept of "enhancements" into discrete enhancements and non-discrete enhancements. Discrete enhancements are features in the new reservoir that were not present at all in the old. Ameren Missouri identified those discrete enhancements as an overflow release structure, a drainage and inspection gallery, a continuous upstream grout curtain, a cementitious floor, a crest concrete roadway and guardrail, crest-to-gallery and foundation drains, and new instrumentation.[FN130] Staff's audit report set the cost of the discrete enhancements identified by Ameren Missouri at $67 million.[FN131]

FN130. Birk Direct, Ex. 106, Page 32, Lines 10-13.

FN131. Staffs' Construction Audit and Prudence Review of Taum Sauk Project for Costs Reported as of October 31, 2010, Ex. 203, Page 17, Chart at Line 6.

27. The non-discrete enhancement identified by Ameren Missouri is chiefly the new and improved foundation of the dam. The new foundation is constructed of roller compacted concrete rather than dumped rock-fill and now meets seismic standards.[FN132] As a result, the remaining service life of the reservoir has been extended by at least 80 years.[FN133]

FN132. Birk Direct, Ex. 106, Page 35, Liens 19-22.

FN133. Transcript, Page 768, Lines 17-23.

28. Staff's audit valued the non-discrete enhancements at an amount in excess of the amount needed to allow Ameren Missouri to recover all rebuild costs not otherwise covered by insurance.FN134

FN134. Transcript, Pages 880-881.

29. The non-discrete enhancements clearly improve the reservoir. But are they "enhancements" within the meaning of the Consent Judgment? The Commission finds that they are not.

30. If the Consent Judgment's allowed cost exception for "enhancements" is broad enough to include non-discrete enhancement such as an improved foundation, then the exception swallows the rule and renders the Consent Judgment's restriction on recovery of rebuilding costs meaningless. Under that interpretation, the Consent Judgment might as well say that Ameren Missouri can recover all building costs not covered by insurance because that would be the result. That cannot have been the intent of the parties to the Consent Judgment, it is not good public policy, and the Commission will not accept it.

31. That leaves the $67 million that Staff and Ameren Missouri identified as discrete enhancements. In principle, those are additions to the new reservoir that were not present in the old reservoir.

32. However, the Commission finds that even the discrete enhancements described by Ameren Missouri and accepted by Staff do not match a reasonable interpretation of the meaning of an enhancement under the Consent Agreement.

33. When Ameren Missouri, then Union Electric, constructed the Taum Sauk plant in the early 1960's they constructed a reservoir that was designed to comply with the state of the art as it existed at that time.FN135 The newly constructed reservoir is designed in compliance with current dam safety requirements. All the new dam safety features that Ameren Missouri and Staff describe as enhancements are required by those current dam safety requirements.FN136 Thus, while those new features are certainly enhancements compared to the original dam, which was designed by 1963 standards, they are not enhancements compared to today's industry standards, as Ameren Missouri's expert witness, Paul Rizzo testified.FN137

FN135. As previously discussed, Ameren Missouri, then Union Electric, did not construct the dam in compliance with even 1963 standards.

FN136. Transcript, Page 812, Lines 5-19.

FN137. Transcript, Page 814, Lines 1-8.

34. If "enhancement" within the meaning of the Consent Judgment is taken to mean just an improvement over the 1963 dam, then again the restriction in the Consent Judgment is essentially meaningless and Ameren Missouri would be invited to recover all its reconstruction costs not covered by insurance. Clearly that was not the intent of the Consent Judgment.

35. The Commission interprets the Consent Judgment to allow Ameren Missouri to recover for "enhancements" measured against today's dam safety standards, not against the much weaker dam safety standards of 1963. Viewed in that manner Ameren Missouri has not described any enhancements for which it can recover construction costs from its ratepayers under the Consent Judgment.

36. An interpretation of the Consent Judgment is not the only reason to disallow Ameren Missouri's recovery of any amount for the rebuild of the Taum Sauk reservoir. Remember, the Commission was not a party to the Consent Judgment and is not bound by its terms. Even if the parties to the Consent Judgment intended to allow Ameren Missouri to recover these costs, the Commission is not bound to follow that intent.

37. As previously indicated, when Staff reviewed the circumstances of the collapse of the reservoir, it concluded that Ameren Missouri's imprudence and recklessness had caused the collapse.FN138 At that time, Staff recommended that Ameren Missouri not be allowed to recover any costs related to the rebuilding of Taum Sauk without any exception.FN139

FN138.*In the Matter of an Investigation Into an Incident in December 2005 at the Taum Sauk Pumped Storage Project Owned and Operated by the Union Electric Company, doing business as AmerenUE*, Case No. ES-2007-0474, Staff's Initial Incident Report, October 24, 2007, Pages 71-72, *See also*, Kind Direct, Ex. 300, Page 5, Lines 6-19.

FN139.*In the Matter of an Investigation Into an Incident in December 2005 at the Taum Sauk Pumped Storage Project Owned and Operated by the Union Electric Company, doing business as AmerenUE*, Case No. ES-2007-0474, Staff's Initial Incident Report, October 24, 2007, Pages 82.

38. Similarly, after the collapse, Ameren Missouri took full responsibility and promised to protect its ratepayers from the consequence of that collapse.[FN140] The Commission intends to hold Ameren Missouri to that promise.

FN140. Kind Direct, Ex. 300, Pages 3-4. Lines 14-23, 1-17.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

Ameren Missouri shall not include any amount of the cost to rebuild the upper reservoir of the Taum Sauk plant in its rate base.

6. Municipal Lighting: What is the appropriate ratemaking treatment for Ameren Missouri's street lighting classes in this case?

Findings of Fact:

Introduction:

1. This issue concerns Ameren Missouri's street lighting class, which is comprised mostly of various municipalities who purchase electricity from Ameren Missouri to light the streets of their communities. A group of municipalities in St. Louis County intervened in this case and they are identified collectively as the Municipal Group. The Municipal Group was also a party to Ameren Missouri's last rate case, ER-2010-0036.

2. In that case, the Commission was concerned that no one could tell whether the rates being paid by the lighting class were just and reasonable because no class cost of service study had examined the lighting class for at least thirty years. Because of its concern, the Commission exempted the lighting class from the rate increase that resulted from that order.[FN141] As the result of a stipulation and agreement in that case, Ameren Missouri agreed to undertake a cost of service study for all rates affecting the lighting class in its next rate case.[FN142]

FN141.*In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, File No. ER-2010-0036, Report and Order, May 28, 2010, Page 100.

FN142. Difani Direct, Ex. 119, Page 3, Lines 1-15.

3. Ameren Missouri's cost of service study in this case indicates the lighting class as a whole is paying approximately $7 million less than the cost to serve that class. To bring the lighting class fully to its cost of service would require a rate increase of 22.41 percent beyond the overall rate increase that will result from this report and order.[FN143] No party has challenged the validity of Ameren Missouri's cost of service study.

FN143. Ex. 551. In a subsequent section of this order, the Commission determines that the lighting class will receive a revenue neutral increase of 4 percent beyond the overall rate increase that will result from this order.

Specific Findings of Fact:

4. The lighting class is divided into three classifications: Street and Outdoor Area Lighting - Company Owned (5M), Street and Outdoor Area Lighting - Customer Owned (6M), and Municipal Street Lighting - Incandescent (7M). The 5M classification is the largest, providing 89.6 percent of Ameren Missouri's total revenue from the lighting class.FN144

FN144. Eastman Direct, Ex. 750, Page 5, Lines 6-7.

5. After conducting its overall class cost of service study, Ameren Missouri undertook a further study to divide the overall revenue requirement to be collected from the lighting class among the three classifications within the lighting class. Again, no party challenged the validity of that study. Instead, the disagreement arose within the 5M classification.

6. The disagreement concerns charges for company-owned distribution facilities. For company-owned distribution facilities, such as poles and spans, installed before September 1988, the municipality is billed a relatively small monthly amount. After September 1988, Ameren Missouri changed its billing policy and charged a relatively large one-time, upfront fee to the municipality when it installed the new pole and span. The municipality then did not have to pay the continuing monthly charge for that pole and span.FN145

FN145. Difani Direct, Ex. 119, Page 8, Lines 7-15.

7. Not surprisingly, the municipalities that had been paying the monthly “pole and span” charge for 22 years or more compared their monthly payments to the upfront charge and started asking whether they had not fully paid for the pole and span by this time. Ameren Missouri agreed that the system should be simplified and proposed to eliminate the “pole and span” charge and instead collect that revenue from the 5M classification as a whole.FN146

FN146. Difani Direct, Ex. 119, Pages 8-9, Lines 18-23, 1-6.

8. The Municipal Group argues that the pre-1988 installation charges should be entirely removed and the revenue those charges collect should not be collected from the lighting class in general or from the 5M classification in particular, arguing that after 22 years those municipalities have surely paid for those poles.FN147

FN147. Eastman Direct, Ex. 750, Page 9, Lines 16-22.

9. The Municipal Group's argument misunderstands the nature of the monthly pre-1988 installation charge (also known as the pole and span charge) and the revenue it collects for Ameren Missouri. As determined in the company's class cost of service study, it costs Ameren Missouri a certain amount of money to provide electric service to the lighting class. Similarly, it costs a certain amount of money to provide services to each of the three classifications within the lighting class. Ameren Missouri has created a number of charges by which it collects that money from those classifications and the lighting class as a whole. Many years ago, Ameren Missouri decided to collect part of the cost of serving the lighting class through the pole and span charge.

10. Payment of the pole and span charge, even for a very long time, does not mean the customer will eventually own the pole and span, just as the payment of the upfront charge after 1988 does not mean the municipality owns the pole and span. The pole and span charge is simply the device the company used to collect a portion of its cost to serve its municipal lighting customers.

11. The situation is analogous to a city government that collects part of the revenue it needs from parking meters. For various reasons, a city may decide that its parking meter rates are too high and should be reduced. However, if the city is to continue to collect the revenue it needs to operate, it may need to increase its sales tax rate to collect the revenue lost when parking meter rates are reduced.

12. Even if the company eliminates a particular charge, the amount of revenue Ameren Missouri needs to serve the lighting class in general and the 5M classification in particular does not change. If Ameren Missouri is to continue to recover its cost of service after eliminating

the pole and span charge, it must increase some other charge to make up the difference.

13. The Municipal Group's suggestion that the revenue lost when the pole and span charge is eliminated not be recovered from the lighting class would mean that Ameren Missouri would have to recover the revenue from some other rate class that the class cost of service studies establish is not responsible for those costs. Such a result would be patently unfair. If the pole and span charge is eliminated, the revenue lost must be collected from the lighting class and the 5M classification in some other manner. The question remains, should the pole and span charge be eliminated as Ameren Missouri proposes?

14. The Municipal Group explains that the elimination of the pole and span charge and the collection of that revenue from the entire 5M rate classification would have a disparate impact on newer and older municipalities. Older cities that installed most of their street lighting years ago and as a result have been paying the pole and span charges for pre1988 poles would no longer pay that charge and could see their rates go down with the elimination of the pole and span charge. On the other hand, newly developing cities that have installed street lighting since 1998 and thus have paid an upfront charge rather than the pole and span charge, would not benefit from the elimination of the pole and span charge and would see their overall rates increase substantially. FN148

FN148. Eastman Direct, Ex. 750, Pages 6-7.

15. Staff suggests that this result is unfair to the newer municipalities and contends the pole and span charge should not be eliminated. FN149 However, the same facts imply that the current arrangement is unfair to the older municipalities that have been paying the pole and span charge. Their subsidization of the newer municipalities will only grow as they continue to pay the pole and span charges and the accumulated revenue Ameren Missouri collects from that charge outstrips the revenue collected through the up-front charges paid by the newer municipalities.

FN149. Scheperle Surrebuttal, Ex. 228, Page 3, Lines 8-13.

16. The pole and span charge needs to be eliminated, but the rate shock that would cause the newer municipalities that paid up-front charges should also be avoided. Therefore, a gradual elimination of the charge is appropriate.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

Based on its findings of fact and conclusions of law, the Commission decides that Ameren Missouri should eliminate the pole and span charge gradually. To avoid the rate shock that would result from the complete elimination of the charge, the Commission directs Ameren Missouri to initially reduce the monthly pole and span charge by half. The reduced revenue resulting from this reduction in the pole and span charge shall be collected from the entire 5M classification within the lighting class. The Commission will consider the total elimination of the pole and span charge in Ameren Missouri's next rate case.

7. Cost of Capital: What return on equity should be used to determine Ameren Missouri's revenue requirement in this case?

Findings of Fact:

Introduction:

1. This issue concerns the rate of return Ameren Missouri will be authorized to earn on its rate base. Rate base includes things like generating plants, electric meters, wires and poles, and the trucks driven by Ameren Missouri's repair crews. In order to determine a rate of return, the Commission must determine Ameren Missouri's cost of obtaining the capital it needs.

2. The relative mixture of sources Ameren Missouri uses to obtain the capital it needs is its capital structure. Ameren Missouri's True-Up Accounting Schedules described Ameren Missouri's actual capital structure as of February 28, 2011 as:

Long-Term Debt	46.702%
Short-Term Debt	00.000%
Preferred Stock	01.063%
Common Equity	52.235%[150]

150. Weiss True-Up Direct, Schedule GSW-TE18-43.

No party has raised an issue regarding capital structure so the Commission will not further address this matter.

3. Similarly, no party has raised an issue regarding Ameren Missouri's calculation of the cost of its long-term debt and preferred stock.

4. Determining an appropriate return on equity is the most difficult part of determining a rate of return. The cost of long-term debt and the cost of preferred stock are relatively easy to determine because their rate of return is specified within the instruments that create them. In contrast, in determining a return on equity, the Commission must consider the expectations and requirements of investors when they choose to invest their money in Ameren Missouri rather than in some other investment opportunity. As a result, the Commission cannot simply find a rate of return on equity that is unassailably scientifically, mathematically, or legally correct. Such a “correct” rate does not exist. Instead, the Commission must use its judgment to establish a rate of return on equity attractive enough to investors to allow the utility to fairly compete for the investors' dollar in the capital market, without permitting an excessive rate of return on equity that would drive up rates for Ameren Missouri's ratepayers. In order to obtain guidance about the appropriate rate of return on equity, the Commission considers the testimony of expert witnesses.

5. Four financial analysts offered recommendations regarding an appropriate return on equity in this case. Robert B. Hevert testified on behalf of Ameren Missouri. Hevert is President of Concentric Energy Advisors, Inc. of Marlborough, Massachusetts. He holds a Bachelor of Science degree in Finance from the University of Delaware and a Master of Business Administration degree from the University of Massachusetts.[FN151] He recommends the Commission allow Ameren Missouri a return on equity of 10.70 percent, within a range of 10.40 percent to 11.25 percent.[FN152]

FN151. Hevert Direct, Ex. 121, Page 1, Lines 16-18.

FN152. Hevert Surrebuttal, Ex. 123, Page 7, Lines 15-18.

6. Billie Sue LaConte testified on behalf of the Missouri Energy Group. LaConte is a consultant in the field of public utility economics and regulation and is a member of the Drazen Consulting Group, Inc.[FN153] LaConte has a Bachelor of Arts in mathematics from Boston University, and a Master of Business Administration degree in finance from the John M. Olin School of Business, Washington University.[FN154] She recommends the Commission allow Ameren Missouri a return on equity within a range of 9.7 percent to 10.6 percent.[FN155]

FN153. LaConte Direct, Ex. 450, Page 1, Lines 5-6.

FN154. LaConte Direct, Ex. 450, Appendix A, Page 2, Lines 1-3.

FN155. LaConte Surrebuttal, Ex. 452, Page 6, Lines 17-18.

7. Michael Gorman testified on behalf of MIEC. Gor-

man is a consultant in the field of public utility regulation and is a managing principal of Brubaker & Associates.[FN156] He holds a Bachelor of Science degree in Electrical Engineering from Southern Illinois University and a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield.[FN157] Gorman recommends the Commission allow Ameren Missouri a return on equity of 9.90 percent, within a recommended range of 9.80 percent to 10.00 percent.[FN158]

FN156. Gorman Direct, Ex. 407, Page 1, Lines 6-7.

FN157. Gorman Direct, Ex. 407, Appendix A, Page 1, Lines 9-12.

FN158. Gorman Surrebuttal, Ex. 409, Page 18, Line 10.

8. Finally, David Murray testified on behalf of Staff. Murray is the Acting Utility Regulatory Manager of the Financial Analysis Department for the Commission. He holds a Bachelor of Science degree in Business Administration from the University of Missouri - Columbia, and a Masters in Business Administration from Lincoln University. Murray has been employed by the Commission since 2000 and has offered testimony in many cases before the Commission.[FN159] Murray recommends a return on equity within a range of 8.25 percent to 9.25 percent, with a recommended midpoint of 8.75 percent.[FN160]

FN159. Staff Report - Revenue Requirement/ Cost of Service, Ex. 201, Appendix 1, Page 49.

FN160. Staff Report - Revenue Requirement/ Cost of Service, Ex. 201, Page 4, Lines 11-12.

Specific Findings of Fact:

9. A utility's cost of common equity is the return investors require on an investment in that company.[FN161] To comply with standards established by the United States Supreme Court, the Commission must authorize a return on equity sufficient to maintain financial integrity, attract capital under reasonable terms, and be commensurate with returns investors could earn by investing in other enterprises of comparable risk.[FN162]

FN161. Gorman Direct, Ex. 407, Page 8, Lines 7-9.

FN162. Gorman Direct, Ex. 407, Page 9, Lines 3-7.

10. Financial analysts use variations on three generally accepted methods to estimate a company's fair rate of return on equity. The Discounted Cash Flow (DCF) method assumes the current market price of a firm's stock is equal to the discounted value of all expected future cash flows. The Risk Premium method assumes that all the investor's required return on an equity investment is equal to the interest rate on a long-term bond plus an additional equity risk premium to compensate the investor for the risks of investing in equities compared to bonds. The Capital Asset Pricing Method (CAPM) assumes the investor's required rate of return on equity is equal to a risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio. No one method is any more “correct” than any other method in all circumstances. Analysts balance their use of all three methods to reach a recommended return on equity.

11. Before examining the analyst's use of these various methods to arrive at a recommended return on equity, it is important to look at another number. For 2010, the average return on equity awarded to integrated electric utilities by state commissions in this country was 10.30 percent. Among states neighboring Missouri, the average authorized return on equity over the same period was 10.23 percent.[FN163]

FN163. Hevert Surrebuttal, Ex. 123, Page 6, Lines 10-17.

12. The Commission mentions the average allowed return on equity not because the Commission should, or would slavishly follow the national average in awarding a return on equity to Ameren Missouri. However, Ameren Missouri must compete with other utilities all

over the country for the same capital. Therefore, the average allowed return on equity provides a reasonableness test for the recommendations offered by the return on equity experts.

13. The 8.75 percent return on equity recommendation offered by Staff's witness is substantially below both the national average awarded return on equity and the recommendations offered by the other expert witnesses. If the Commission were to authorize the return on equity recommended by Staff, it would apparently be the lowest "non-penalty" return on equity authorized in the United States in the last thirty years.FN164

FN164. Hevert Rebuttal, Ex. 122, Page 16, Footnote 19.

14. In developing his recommendation for Staff, Murray gave primary weight to his multi-stage DCF analysis.FN165 Murray's multi-stage DCF analysis results in a low recommended return on equity because the third stage of his analysis relies on a low longterm growth estimate of 3 to 4 percent, with a midpoint of 3.5 percent, to derive an estimated cost of equity ranging from 8.4 percent to 9.15 percent, with a midpoint of 8.775 percent.FN166

FN165. Staff Report - Revenue Requirement/ Cost of Service, Page 19, Lines 14-15.

FN166. Staff Report - Revenue Requirement/ Cost of Service, Page 20, Lines 1-10.

15. Murray initially based his long-term growth rate on a 2003 study published in Mergent *Public Utility and Transportation Manual*. Because Murray could not replicate Mergent's data, he decided to perform his own study to estimate long-term growth rates based on historical growth rates for a set of electric utilities during the period between 1968 and 1999. That study showed an average annual growth rate of 3.59 percent.FN167

FN167. Staff Report - Revenue Requirement/ Cost of Service, Page 23, Lines 5-13.

16. Murray admittedly did not use "rigid selection criteria" in determining which utilities to include in his study and it appears that the selection of data to study was based more on the ready availability of that information to Staff than to any rational basis for that selection.FN168

FN168. Staff Report - Revenue Requirement/ Cost of Service, Page 22-23, Lines 5-26,1-4.

17. In contrast to the very low long-term growth rate used by Murray, Ameren Missouri's witness, Robert Hevert, used a long-term growth rate of 5.75 percent, based on the real GDP growth rate of 3.28 percent from 1929 through 2009, plus an inflation rate of 2.40 percent.FN169 In his multi-stage DCF analysis, Michael Gorman used a long-term growth rate of 4.7 percent based on consensus economists' projected 10-year GDP growth rate as published in Blue Chip Economic Indicators.FN170 Billie LaConte performed a two-stage DCF analysis, but used an average long-term growth rate of 5.57 percent based on the average 5-year growth rate for her proxy group of companies.FN171 In sum, the long-term growth rates used by the other return on equity witnesses are substantially higher than the rate used by Murray.

FN169. Hevert Direct, Ex. 121, Page 29, Lines 3-5.

FN170. Gorman Direct, Ex. 407, Page 23, Lines 14-18.

FN171. LaConte Direct, Ex. 450, Page 11, Lines 1-4.

18. In support of his use of a very low long-term growth rate, Murray points to a 2009 research report by Goldman Sachs that uses a 2.5 percent perpetual growth rate in its DCF analysis. Murray argues that such a low growth rate is consistent with what investors use in practice.FN172 However, Murray conceded that the 2.5 percent growth rate used by Goldman Sachs in its report is a real growth rate in that it does not take into account inflation.FN173 Analysis of growth rates for purposes of estimating the cost of equity usually looks at nominal growth rates. If a forecast of long-term inflation were added to Goldman Sachs' real growth rate to estimate a

nominal growth rate, then Staff's forecasted growth rate would be more in line with the forecasts offered by the other experts.FN174

FN172. Staff Report - Revenue Requirement/ Cost of Service, Page 23-24, Lines 26-27, 1-13.

FN173. Transcript, Page 1177, Lines 3-6.

FN174. Hevert Rebuttal, Ex. 122, Pages 46-47, Lines 23-29, 1-2.

19. In an effort to support his low recommended return on equity, Murray points to various valuation analyses regarding Ameren Missouri done by financial analysts for purposes other than the establishment of rates. Murray reports that in general, experts in the field of asset valuation consistently apply a much lower cost of equity to cash flows generated from regulated utility operations as compared to the estimates of cost of equity from rate of return witnesses in the utility ratemaking process.FN175 Murray's clear implication is that aside from him, all other rate of return witnesses are getting it wrong.FN176

FN175. Murray Rebuttal, Ex. 219, Page 13, Lines 3-9.

FN176. Transcript, Page 1185, Lines 5-21.

20. Murray's reliance on valuation analyses to support the reasonableness of his return on equity recommendation is misplaced. Murray acknowledged that he has no experience in asset valuation.FN177 In his surrebuttal testimony, Robert Hevert explained in great detail why the valuation analyses cited by Staff are different than the analysis necessary to evaluate a reasonable return on equity in the rate making process.FN178 The Commission is persuaded by that explanation and accepts Mr. Hevert's explanation without repeating his arguments. In sum, as MEG's witness, Billie Sue LaConte, who has done asset valuation work in the past, indicated, the principles and methods involved in valuing physical assets are different than the principles and methods involved in estimating a utility's cost of equity.FN179

FN177. Transcript, Pages 1181-1182.

FN178. Hevert Surrebuttal, Ex. 123, Pages 13-33.

FN179. Transcript, Page 1215, Lines 15-21.

21. The Commission finds that Staff's recommended return on equity of 8.75 percent is not a reasonable return on equity for Ameren Missouri.

22. Aside from Staff's outlying recommendation, the return on equity recommendations of the other expert witnesses are fairly close together. LaConte and Gorman both recommend a return on equity near 10.0 percent. Hevert for Ameren Missouri recommends a return on equity of 10.7 percent, but no less than 10.4 percent.

23. Hevert's recommended return on equity is higher than the other recommendations in large part because he over-estimates future long-term growth in his various DCF analyses, making them too high to be reasonable estimates of long-term sustainable growth.FN180 When Hevert's long-term growth rates are adjusted to use more sustainable growth estimates based on published analyst's projections, his multi-stage DCF analysis produces a rate of return more in line with the estimates of LaConte and Gorman.FN181

FN180. Gorman Rebuttal, Ex. 408, Pages 8-9, Lines 20-23, 1-3.

FN181. Gorman Surrebuttal, Ex. 409, Page 22, Lines 1-13.

24. MEG's witness Billie LaConte recommends an ROE within a range of 9.7 percent to 10.6 percent. In her direct testimony she recommended an ROE of 10.2 percent FN182, but in her surrrebuttal testimony she recommended the allowed ROE be set at the lower end of her range between 9.7 and 10.0 percent. FN183

FN182. LaConte Direct, Ex. 450, Page 18, Lines 16-17.

FN183. LaConte Surrebuttal, Ex. 452, Page 8, Lines 10-11.

25. LaConte lowered her recommended ROE based on

her CAPM and ECAPM studies that indicated very low numbers, a full point or more below her DCF analyses, which the Commission has usually found to be more reliable. LaConte did not explain why she decided to place greater reliance on her CAPM and ECAPM studies in her surrebuttal recommendation than she had in her direct testimony and the Commission finds no justification for doing so. At any rate, LaConte testified that any percentage within her range of 9.7 to 10.6 percent would be reasonable.[FN184]

FN184. Transcript, Pages 1215-1216, Lines 22-25, 1-6.

26. MIEC's witness, Michael Gorman, recommended a return of 9.9 percent, within a range of 9.8 to 10.0 percent. He also over relies on his unreasonably low Sustainable Growth DCF analysis to pull down the average of his more reasonable Constant Growth DCF and Multi-Stage DCF analyses.[FN185] If Gorman were to rely more heavily on his Constant Growth DCF result of 10.47 percent and his Multi-Stage Growth DCF of 10.16 percent, his analyses would indicate an allowed ROE near 10.2 percent.

FN185. Gorman Surrebuttal, Ex. 409, Page 18, Table 1.

27. An allowed ROE of 10.2 percent would still be below the national average allowed ROE of 10.3 percent.

Conclusions of Law:

A. In assessing the Commission's ability to use different methodologies to determine just and reasonable rates, the Missouri Court of Appeals has said:

Because ratemaking is not an exact science, the utilization of different formulas is sometimes necessary. … The Supreme Court of Arkansas, in dealing with this issue, stated that there is no ‘judicial mandate requiring the Commission to take the same approach to every rate application or even to consecutive applications by the same utility, when the commission in its expertise, determines that its previous methods are unsound or inappropriate to the particular application’ (quoting *Southwestern Bell Telephone Company v. Arkansas Public Service Commission,* 593 S.W. 2d 434 (Ark 1980).[FN186]

FN186.*State ex rel. Assoc. Natural Gas Co. v. Public Service Commission,* 706 S.W. 2d 870, 880 (Mo. App. W.D. 1985).

Furthermore,

Not only can the Commission select its methodology in determining rates and make pragmatic adjustments called for by particular circumstances, but it also may adopt or reject any or all of any witnesses' testimony.[FN187]

FN187.*State ex rel. Assoc. Natural Gas Co. v. Public Service Commission,* 706 S.W. 2d 870, 880 (Mo. App. W.D. 1985).

B. In another case, the Court of Appeals recognized that the establishment of an appropriate rate of return is not a “precise science”:

While rate of return is the result of a straight forward mathematic calculation, the inputs, particularly regarding the cost of common equity, are not a matter of ‘precise science,’ because inferences must be made about the cost of equity, which involves an estimation of investor expectations. In other words, some amount of speculation is inherent in any ratemaking decision to the extent that it is based on capital structure, because such decisions are forward-looking and rely, in part, on the accuracy of financial and market forecasts.[FN188]

FN188.*State ex rel. Missouri Gas Energy v. Public Service Commission,* 186 S.W.3d 376, 383 (Mo App. W.D. 2005).

C. In its brief, Staff suggests that the Commission adopt what it describes as a new paradigm to determine an appropriate authorized return on equity for Ameren Missouri. Staff contends that the United States Supreme Court's *Bluefield* decision establishes a sort of zone of reasonableness. According to the Supreme Court, rates that are insufficient to yield a reasonable return on the company's investment are confiscatory and would deprive the utility of its property in violation of the Fourteenth Amendment. Staff contends the rate that would be unconstitutionally confiscatory sets the lower bound of the zone of reasonableness. The *Bluefield* decision also states that the utility is not entitled to profits that would be realized or anticipated in highly profitable enterprises or speculative ventures. Staff claims that such a rate would be the upper bound of the zone of reasonableness.

D. Staff claims that through the testimony of David Murray it has attempted to establish the lower bound of this zone of reasonableness, in other words, the level below which the authorized rate would be unconstitutionally confiscatory. Staff claims that the rate proposed by Murray is the lowest reasonable rate at the edge of confiscation and suggests that the Commission must set Ameren Missouri's rates at that level unless it has a valid regulatory reason to award the company a higher rate. Staff contends there is no valid reason to set a rate higher than the lowest reasonable rate that it indicates is at the very edge of confiscation.

E. Staff's “new paradigm” adds nothing to the Commission's consideration of an appropriate return on equity. Of course, the Commission is trying to find the lowest reasonable rate that protects the interests of ratepayers and shareholders. That is what it has always done. In claiming that the rate proposed by its witness is the lowest reasonable rate, Staff simply begs the question of whether the rate proposed by its witness is reasonable. It is certainly the lowest rate proposed, but that does not make it a reasonable rate. Indeed, the Commission has found as a matter of fact that the rate proposed by Staff is not reasonable. Nothing is to be gained by trying to determine the edge of confiscation when under either the old or the new paradigm, the Commission is simply obligated to determine a reasonable rate for the utility.

Decision:

Based on the evidence in the record, on its analysis of the expert testimony offered by the parties, and on its balancing of the interests of the company's ratepayers and shareholders, as fully explained in its findings of fact and conclusions of law, the Commission finds that 10.2 percent is a fair and reasonable return on equity for Ameren Missouri. The Commission finds that this rate of return will allow Ameren Missouri to compete in the capital market for the funds needed to maintain its financial health.

8. Fuel Adjustment Clause Issues:

A. Should the Commission authorize Ameren Missouri to continue its current Fuel Adjustment Clause (FAC) or should the Commission discontinue or order modifications to the FAC?

Findings of Fact:

Introduction:

1. In a previous Ameren Missouri rate case, ER-2008-0318, the Commission allowed Ameren Missouri to implement a fuel adjustment clause.[FN189] The approved fuel adjustment clause includes an incentive mechanism that requires Ameren Missouri to pass through to its customers 95 percent of any deviation in fuel and purchased power costs from the base level. The other 5 percent of any deviation is retained or absorbed by Ameren Missouri.[FN190]

FN189. *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service* , Report and Order, Case No. ER-2008-0318, January 27, 2009, Pages 69-70.

FN190. *Id.* at Page 76.

2. In this case, Ameren Missouri proposed that the Commission allow it to continue to use its existing fuel adjustment clause.[FN191] AARP and Consumers Council urge the Commission to discontinue that fuel adjustment clause. Staff did not oppose the continuation of the fuel adjustment clause, but advises the Commission to change the sharing mechanism to create an 85/15 split, with Ameren Missouri retaining or absorbing 15 percent of any deviation from the base level of fuel and

purchased power costs. Public Counsel supports Staff's position. The Commission will address the proposed modification of the sharing mechanism in the next section of this report and order.

FN191. Barnes Direct, Ex. 102, Page 4, Lines 11-13.

Specific Findings of Fact:

3. In a previous Ameren Missouri rate case, ER-2008-0318, the Commission found that Ameren Missouri should be allowed to establish a fuel adjustment clause because its fuels costs were substantial, beyond the control of the company's management, and volatile in amount. The Commission also found that Ameren Missouri needed a fuel adjustment clause to have a sufficient opportunity to earn a fair return on equity and to be able to compete for capital with other utilities that have a fuel adjustment clause.[FN192] In the same rate case, the Commission found that a 95/5 sharing mechanism would give Ameren Missouri a sufficient opportunity to earn a fair return on equity, while protecting customers by preserving the company's incentive to be prudent.[FN193]

FN192.*In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service* , Report and Order, Case No. ER-2008-0318, January 27, 2009, Pages 69-70.

FN193.*Id.*, at Page 76.

4. Nothing has changed in the years since the Commission established Ameren Missouri's fuel adjustment clause to cause the Commission to change that decision. The Commission again finds that Ameren Missouri's fuel and purchased power costs are substantial, $888 million in the test year, comprising 49 percent of the company's total operations and maintenance expense.[FN194] Furthermore, the revenue the company receives from off-system sales, which is also tracked through the fuel adjustment clause, is also substantial.[FN195] These fuel and purchased power costs continue to be dictated by national and international markets, and thus are outside the control of Ameren Missouri's management.[FN196] Finally, these costs and revenues continue to be volatile. For example, the price Ameren Missouri was able to obtain in the market for off-system electricity sales decreased 45 percent from 2008 to 2009 before partially recovering during the trued-up test year.[FN197]

FN194. Barnes Direct, Ex. 102, Page 6, Lines 19-22.

FN195. Barnes Direct, Ex. 102, Page 6, Lines 22-24.

FN196. Barnes Direct, Ex. 102, Page 6, Lines 24-27.

FN197. Barnes Direct, Ex. 102, Page 7, Lines 2-4.

5. Furthermore, the Commission finds that Ameren Missouri still needs a fuel adjustment clause to help alleviate the effects of regulatory lag as net fuel costs continue to rise. Ameren Missouri's regulatory lag problems have not improved since its last rate case. In recent years, the company has been unable to earn its allowed rate of return,[FN198] and in large part, that problem is due to fuel-related issues. Even with the fuel adjustment clause in place, Ameren Missouri's return on equity for the year ending December 2009, was only 7.27 percent. Ameren Missouri's retail operating income for the test year would have been approximately $30 million lower if the fuel adjustment clause had not been in effect, further reducing the company's ability to earn its allowed return.[FN199] In addition, Ameren Missouri still must compete in the capital markets with other utilities and the vast majority of those utilities have fuel adjustment clauses.[FN200]

FN198. Weiss Direct, Ex. 130, Pages 33-34, Lines 12-23, 1-4.

FN199. Barnes Direct, Ex. 102, Pages 7-8, Lines 22-23, 1-6.

FN200. Transcript, Page 1516, Lines 22-24.

Conclusions of Law:

A. Section 386.266.1, RSMo (Supp. 2010), the statute that allows the Commission to establish a fuel adjustment clause provides as follows:

Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge or periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation. The commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities.

Subsection 4 of that statute sets out some of the provisions that must be included in a fuel adjustment clause as follows:The commission shall have the power to approve, modify, or reject adjustment mechanisms submitted under subsections 1 to 3 of this section only after providing the opportunity for a full hearing in a general rate proceeding, including a general rate proceeding initiated by complaint. The commission may approve such rate schedule after considering all relevant factors which may affect the cost or overall rates and charges of the corporation, provided that it finds that the adjustment mechanism set forth in the schedules:

(*1) Is reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity;*

(2) Includes provisions for an annual true-up which shall accurately and appropriately remedy any over- or under-collections, including interest at the utility's short-term borrowing rate, through subsequent rate adjustments or refunds;

(3) In the case of an adjustment mechanism submitted under subsections 1 and 2 of this section, includes provisions requiring that the utility file a general rate case with the effective date of new rates to be no later than four years after the effective date of the commission order implementing the adjustment mechanism. …

(4) In the case of an adjustment mechanism submitted under subsections 1 or 2 of this section, includes provisions for prudence reviews of the costs subject to the adjustment mechanism no less frequently than at eighteenmonth intervals, and shall require refund of any imprudently incurred costs plus interest at the utility's short-term borrowing rate. (emphasis added)

Subsection 4(1) is emphasized because that is the key requirement of the statute. Any fuel adjustment clause the Commission allows Ameren Missouri to implement must be reasonably designed to allow the company a sufficient opportunity to earn a fair return on equity.

B. Subsection 7 of the fuel adjustment clause statute provides the Commission with further guidance, stating the Commission may:

take into account any change in business risk to the corporation resulting from implementation of the adjustment mechanism in setting the corporation's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the corporation.

Finally, subsection 9 of that statute requires the Commission to promulgate rules to “govern the structure, content and operation of such rate adjustments, and the procedure for the submission, frequency, examination, hearing and approval of such rate adjustments.”In compliance with the requirements of the statute, the Commission promulgated Commission Rule 4 CSR 240-3.161, which establishes in detail the procedures for submission, approval, and implementation of a fuel adjustment clause.

C. Specifically, Commission Rule 4 CSR 240-3.161(3) establishes minimum filing requirements for an electric utility that wishes to continue its fuel adjustment clause in a rate case subsequent to the rate case in which the fuel adjustment clause was established. Ameren Missouri has met those filing requirements.

Decision:

Ameren Missouri still needs to have a fuel adjustment clause in place to help alleviate the effects of regulatory lag if it is to have a reasonable opportunity to earn a fair return on its investments. The Commission concludes that Ameren Missouri should be allowed to continue to implement the previously approved fuel adjustment clause.

B. Should the sharing percentage in Ameren Missouri's FAC be changed from 95/5 percent to 85/15 percent?

Findings of Fact:

Introduction:

6. While Staff did not oppose the continuation of Ameren Missouri's fuel adjustment clause, it advised the Commission to modify the sharing mechanism within the fuel adjustment clause to increase the percentage of costs and income absorbed or retained by Ameren Missouri from 5 percent to 15 percent. Public Counsel supports that proposed modification.

7. Staff offered four reasons why the sharing percentage should be changed. First, Staff initially gave Ameren Missouri credit for asking that its net base fuel costs be rebased in this rate case. Staff explained that the request to rebase those costs showed that Ameren Missouri has a proper incentive to avoid forfeiting the 5 percent share it would lose under the fuel adjustment clause if its net base fuel costs were not rebased.[FN201] However, later in the case, Staff turned that positive factor into a negative by claiming that Ameren Missouri's willingness to agree to a level of off-system sales revenue that the company indicated was likely to be too low, showed that the company did not have a proper incentive to get it right.[FN202] Second, Staff claims that the results of a recent prudence audit of Ameren Missouri's fuel adjustment clause in File No. EO-2010-0255 justify imposing a larger sharing percentage on Ameren Missouri.[FN203] Third, Staff asserts that a larger sharing percentage might have provided Ameren Missouri a greater incentive to avoid the miscalculation of an input into its FAC rate that it identified in the true-up of the first recovery period of its fuel adjustment clause.[FN204] Fourth, and finally, Staff claims that because Ameren Missouri's off-system sales are down since it implemented a fuel adjustment clause, perhaps it does not have sufficient incentive to maximize off-system sales.[FN205]

FN201. Staff Report - Revenue Requirement / Cost of Service, Ex. 201, Page 112, Lines 2-9.

FN202. Mantle Surrebuttal, Ex. 218, Page 12, Lines 5-7.

FN203. Staff Report - Revenue Requirement / Cost of Service, Ex. 201, Page 113, Lines 15-20.

FN204. Staff Report - Revenue Requirement / Cost of Service, Ex. 201, Page 114, Lines 7-10.

FN205. Staff Report - Revenue Requirement / Cost of Service, Ex. 201, Page 115, Lines 5-7.

8. In addition to Staff's concerns, Public Counsel points out that one of the incentives Ameren Missouri has used in past cases to justify use of the 95/5 sharing mechanism has gone away. Ameren Missouri is no longer involved in a coal pool purchasing arrangement with its unregulated merchant generation plants in Illinois and thus no longer shares the unregulated affiliates' profit motive to minimize its coal costs.[FN206] The Commission will address each of Staff and Public Counsel's concerns in turn.

FN206. Kind Rebuttal, Ex. 302, Page 15, Lines 16-23.

Specific Findings of Fact:

9. In her rebuttal testimony, Ameren Missouri's witness, Lynn Barnes, testified that she believes the net base fuel costs used in calculating rates for this case are likely to be lower than actual future costs because the three-year historical average used to calculate those costs includes power prices that are higher than Ameren Missouri is likely to experience in the future. As a result, Ameren Missouri believes it will likely need to absorb more net fuel costs under the existing 95/5 sharing mechanism.[FN207] Staff turned that argument against Ameren Missouri by claiming that if the company had a sufficient incentive under the 95/5 sharing mechanism it would have fought harder to establish a proper determination of net base fuel costs.[FN208]

FN207. Barnes Rebuttal, Ex. 103, Page 8, Lines 1-13.

FN208. Mantle Surrebuttal, Ex. 218, Page 12, Lines 5-7.

10. The fuel cost issues about which Staff expressed a concern were settled for this case by a stipulation and agreement signed by Staff and approved by the Commission.FN209 Ameren Missouri's witnesses indicated that the off-system sales component of those fuel costs were based on a three-year historical average of actual off-system sales rather than a projection of future sales that the company believes would better reflect the amount of sales it is likely to make in the future. Nevertheless, Ameren Missouri accepted the use of the historical average sales as part of the settlement.

FN209. Third Non-Unanimous Stipulation and Agreement, filed May 6, 2011, and approved by the Commission on June 1, 2011.

11. Staff argues that Ameren Missouri's willingness to accept what it believes to be a flawed basis for the calculation demonstrates that it does not have a sufficient incentive to "get it right." The Commission finds that Ameren Missouri's pragmatic acceptance of the use of historical average sales in the calculation of future off-system sales simply reflects the company's acceptance of the position the Commission clearly stated in previous Ameren Missouri rate case.

12. This issue was presented to the Commission in File Number ER-2007-0002. In that case, certain parties argued the Commission should establish the amount allowed for offsystem sales based on Ameren Missouri's future budgets. In refusing to allow for the use of future budgeted amounts, the Commission stated:
[s]ince the Commission uses historical expenses and revenues to set rates, it would be fundamentally unfair to reach forward to grab a single budget item to reduce AmerenUE's cost of service, while ignoring other anticipated costs that might increase that cost of service. FN210

FN210.*In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area*, Case No. ER-2007-0002, Report and Order, May 22, 2007, Page 32.

Far from evidencing a lack of incentive to "get it right", Ameren Missouri's decision to settle the fuel cost issue simply illustrates the company's willingness to comply with a position clearly stated in a recent Commission decision.

13. Staff's second argument asserts that an 85/15 sharing mechanism is appropriate because the Commission made a finding that Ameren Missouri acted imprudently in its review of the company's first prudence review in file number EO-2010-0255.FN211 The Commission did find that Ameren Missouri acted imprudently in that prudence review. However, the imprudence that the Commission found was related to Ameren Missouri's failure to flow revenue received from certain contracts through the fuel adjustment clause. Ameren Missouri had entered into those contracts in an attempt to replace a portion of the revenue it lost when production and the use of electricity was reduced at the Noranda aluminum smelter because of a January 2009 ice storm. Despite disagreeing with Ameren Missouri regarding the proper interpretation of a provision of the fuel adjustment clause tariff, the Commission did not find that Ameren Missouri had acted imprudently in deciding to enter into those replacement contracts. In short, the Commission's decision in EO- 20100255 does not support the argument that Ameren Missouri needs a larger financial incentive within the fuel adjustment clause.

FN211.*In the Matter of the First Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of Union Electric Company, d/b/a Ameren Missouri*, EO-2010-0255, Report and Order, April 27, 2011.

14. Staff's third argument is that a larger sharing percentage within the fuel adjustment clause might have provided Ameren Missouri with a greater incentive to avoid the miscalculation of an input into its fuel adjustment clause rate that was identified in the recent true-up of the first recovery period under that fuel adjustment clause. In that case, ER-2010-0274, a mutual mistake by

Staff and Ameren Missouri about the proper calculation of an input resulted in Ameren Missouri collecting less money than it should have collected under the fuel adjustment clause. Extensive testimony was received regarding the details of that mistake, but that evidence did not show that giving Ameren Missouri a greater financial incentive by increasing the sharing percentage of the fuel adjustment clause would have made the mistake less likely to have occurred.

15. Staff's fourth argument asserts that a recent decline in Ameren Missouri's off-system sales might be attributable to a reduction in the company's incentive to make those sales. Staff points out that Ameren Missouri's total off-system sales decreased in four of the five accumulation periods since the Commission first approved Ameren Missouri's fuel adjustment clause.[FN212] However, the reduction in off-system sales that Staff notes is entirely explained by an increase in retail sales during the same period.[FN213] More retail sales means less power is available to sell off-system. In addition, during this period Ameren Missouri experience several major planned generator outages that reduce the amount of electricity available for off-system sales.[FN214] Ultimately, under cross-examination, Staff's witness conceded that she was not contending that Ameren Missouri lacks sufficient incentive to make off-system sales.[FN215]

FN212. Staff Report, Revenue Requirement/Cost of Service, Ex. 201, Page 115, Lines 1-4.

FN213. Haro Rebuttal, Ex. 125, Page 19, Lines 1-8.

FN214. Haro Rebuttal, Ex. 125, Pages 19-21.

FN215. Transcript, Pages 1605-1606, Lines 23-25, 1.

16. The final argument offered to support the contention that Ameren Missouri needs additional incentives to minimize its fuel costs was initially offered by Public Counsel's witness, Ryan Kind. He pointed out that the pool arrangement for purchasing coal that Ameren Missouri formerly had with its unregulated affiliated generating company in Illinois has ended.[FN216] In its report and order that initially established the 95/5 sharing mechanism for Ameren Missouri's fuel adjustment clause, the Commission noted that Ameren's strong incentive to minimize coal costs for its unregulated operations would also benefit Ameren Missouri. The Commission cited that incentive as a justification for believing that a 95/5 sharing mechanism would provide the company with a sufficient incentive to minimize its fuel costs.[FN217]

FN216. Kind Rebuttal, Ex. 302, Page 15, Lines 13-23.

FN217.*In the Matter of Union Electric Company, d/b/a Ameren UE's Tariffs to Increase its Annual Revenues for Electric Service* , Report and Order, Case No. ER-2008-0318, January 27, 2009, Page 73

17. Ameren Missouri is no longer in a coal pool arrangement with its Illinois affiliates because FERC rule changes have forbidden the practice and because it was no longer financially beneficial to Ameren Missouri to be involved in the coal pool.[FN218] Thus, one incentive to minimize one aspect of the company's fuel costs has been eliminated. However, that was only one incentive, and its elimination does not have a significant impact on Ameren Missouri's remaining overall incentive to minimize its fuel purchasing costs.

FN218. Transcript, Page 1460, Lines 3-20.

18. No other electric utility in Missouri buys coal under a coal purchasing pool arrangement and the Commission has allowed those utilities to implement their fuel adjustment clauses using a 95/5 sharing mechanism. Indeed, no other electric utility in the country buys its coal under a coal purchasing arrangement since such arrangements are no longer allowed by FERC rules, yet 90 percent of electric utilities operate using fuel adjustment clauses and the vast majority of those have no percentage sharing mechanism of any kind. [FN219]

FN219. Rygh Rebuttal, Ex. 126, Page 16, Lines 14-15.

19. Furthermore, changing the sharing percentage without a good reason to do so would lead investors to question the future of Ameren Missouri's fuel adjustment clause. In the words of Gary Rygh, a managing director at Barclays Capital, Inc.:

If the Commission were willing to significantly degrade the existing FAC and pass-through mechanism apart from findings in the established review processes, and despite the lack of credible evidence that Ameren Missouri in fact is mismanaging its net fuel costs, investors would view such a change as capricious and designed to inflict significant harm on the Company.FN220

FN220. Rygh Rebuttal, Ex. 126, Page 16, Lines 3-8.

Because of investors concerns, ratepayers would be burdened with excessive costs each time Ameren Missouri accesses the capital markets.FN221

FN221. Rygh Rebuttal, Ex. 126, Page 17, Lines 3-4.

20. Most significantly, a change in the sharing mechanism to require Ameren Missouri to absorb 15 percent of net fuel cost changes instead of the current 5 percent would impose a significant financial burden on the company. If the proposed 85/15 sharing mechanism had been in place since the fuel adjustment clause was put into effect instead of the actual 95/5 sharing mechanism, Ameren Missouri would have been required to absorb an additional $22 million in net fuel costs.FN222 That would be a heavy burden on a company that is already having difficulty earning its allowed rate of return.

FN222. Transcript, Page 1583, Lines 3-10.

Conclusions of Law:

There are no additional conclusions of law for this subissue.

Decision:

Staff's stated reasons for experimenting with adjusting the sharing mechanism of Ameren Missouri's fuel adjustment clause to implement an 85/15 split do not withstand scrutiny. Imposing a significant financial burden on the company simply to experiment with an alternative sharing percentage would be unfair to the company. The Commission finds that there is no reason to change the sharing percentages in the fuel adjustment clause under which Ameren Missouri has operated for the past several years. The Commission will retain the current 95/5 sharing mechanism included in Ameren Missouri's fuel adjustment clause.

C. Should the length of the recovery periods for the FAC be reduced from twelve (12) months to eight (8) months?

Findings of Fact:

Introduction:

21. Ameren Missouri's current FAC tariff provides that the company accumulates fuel costs during accumulation periods that are four months long. Two months after the end of the accumulation period, Ameren Missouri files tariff sheets to change its fuel and purchased power adjustment (FPA) that have a 60-day effective date. The Commission must act to approve or reject that change within 60 days. Once the change in the FPA goes into effect, Ameren Missouri collects the difference between the actual total energy costs and the base energy cost over a recovery period of 12 months.FN223

FN223. Staff Report, Revenue Requirement/ Cost of Service, Ex. 201, Page 117, Lines 13-21.

22. The current process for cost recovery under the fuel adjustment clause means that Ameren Missouri must wait up to 22 months before fully recovering its net fuel costs.

23. Staff proposes to reduce that lag period by four months by shortening the cost recovery period from 12 months to 8 months. That change would allow Ameren Missouri to recover its net fuel costs more quickly.

24. Not surprisingly, Ameren Missouri supports the proposed reduction in the recovery period. MIEC however opposes that change, arguing that the 12-month recovery period moderates the adjustment by spreading any recovery or refund over a full calendar year. MIEC contends spreading the recovery or refund over a full year avoids concentrating the reconciliation in a shortened period where some classes could have a disproportionate share of usage and thereby incur a disproportionate share of the recovery costs or collect a disproportionate share of any refund.[FN224]

FN224. Brubaker Rebuttal, Ex. 405, Page 14, Lines 11-18.

Specific Findings of Fact:

25. Changing the 12-month recovery period to an 8-month recovery period will not change the total amount of net fuel costs that Ameren Missouri will be able to recover from its customers. The change will however allow the company to recover those costs more quickly and thereby improve Ameren Missouri's cash flow.[FN225]

FN225. Transcript, Page 1737, Lines 15-21.

26. Improving cash flow is important to Ameren Missouri because it has been suffering from the effects of regulatory lag and as a result has failed to earn its allowed return on its investment over the past several years.[FN226]

FN226. Weiss Direct, Ex. 130, Pages 33-34, Lines 12-23, 1-4.

27. Moving from a 12-month recovery period to an 8 month recovery period will improve Ameren Missouri's cash flow, but also has the effect of increasing the volatility of the fuel adjustment clause. In other words, the necessary adjustments will tend to be larger, either up or down, and customers will pay the adjusted rates sooner.[FN227]

FN227. Transcript, Pages 1570-1571, Lines 20-25, 1-20.

28. MIEC suggests that changing the recovery period from 12 months to 8 months could have the effect of concentrating the reconciliation into a shortened period where some classes could have a disproportionate share of usage. For example, the residential class, which uses a lot of electricity in the summer for air conditioning, could pay a disproportionate share during an 8-month recovery period that includes the summer months. However, a chart presented by Ameren Missouri's witness, Lynn Barnes, demonstrates that there are only minimal differences in class percentages of kilowatt-hour sales regardless of whether a 12-month or 8-month recovery period is used.[FN228] Thus, concerns about concentration of the reconciliation are unfounded.

FN228. Barnes Surrebuttal, Ex. 104, Pages 2-3, Lines 4-18, 1-4.

Conclusions of Law:

There are no additional conclusions of law for this sub-issue.

Decision:

The decision on this sub-issue comes down to a weighing of the need to increase Ameren Missouri's cash flows against the desire to reduce the volatility of recovery of net fuel costs under the fuel adjustment clause. There is nothing legally correct or preordained about either a 12-month or an 8-month recovery period, the recovery period could just as easily be set at 6, 9, or 18 months, or at some point in between. On balance, the Commission concludes that improved cash flows for Ameren Missouri outweigh concerns about an increase in volatility in recovery under the fuel adjustment clause. The recovery period shall be changed to 8 months.

D. Should the Company have the ability to adjust the FPAC rate for errors in calculations that may have occurred since the FAC Rider was granted to Ameren Missouri?

Findings of Fact:

Introduction:

29. In addition to the broad issues regarding the fuel adjustment clause tariff that have previously been discussed, Ameren Missouri has submitted specific proposed language for that tariff.FN229 The exemplar tariff proposed by Ameren Missouri would add the following clause to the section regarding true-up of the FAC:

FN229. Barnes Rebuttal, Ex. 103, Schedule LMB-ER4.

The true-up adjustment shall be the difference between the revenue billed and the revenues authorized for collection during the Recovery Period, *plus amounts necessary to correct over- or under-collections due to errors made in calculating adjustments to the FPAC rate that impacted the Recovery Period.*(new language is in *italics*.)

30. Staff objects to the inclusion of the new language proposed by Ameren Missouri because under the formula used to calculate the FAC adjustment, each succeeding FPAC is linked to all previous FPACs. Staff is concerned that the additional language proposed by Ameren Missouri would allow the company to claim an adjustment during any true-up for any perceived discrepancy in calculating the FPAs that have occurred since March 1, 2009, when Ameren Missouri's fuel adjustment clause first went into effect. Staff is concerned that this provision would complicate the true-up process and would deny finality to Commission decisions regarding the true-up.FN230

FN230. Roos Surrebuttal, Ex. 225, Pages 4-5, Lines 17-24, 1-3.

Specific Findings of Fact:

31. This disagreement between Staff and Ameren Missouri is related to a dispute pending before the Commission in a current Ameren Missouri true-up, File Number ER2010-0274. In that case, Ameren Missouri sought to adjust its true-up amounts to collect a sum of money that it had failed to collect due to an error in calculating the FPAC. The Commission had not yet decided that case at the time this case was heard, but on June 29, 2011, issued a Report and Order that allowed Ameren Missouri to collect the amount necessary to correct the identified error.FN231

FN231.*In the Matter of the First True-Up Filing Under the Commission-Approved Fuel Adjustment Clause of Union Electric Company, d/b/a Ameren Missouri*, File No. ER-2010-0274, Report and Order, June 29, 2011.

32. The tariff language proposed by Ameren Missouri would not be limited to the particular error that the Commission found could be corrected in File Number ER- 20100274 and would instead provide Ameren Missouri with broad authority to correct other errors that might be identified in the future.

Conclusions of Law:

There are no additional conclusions of law for this subissue.

Decision:

The Commission has found in favor of Ameren Missouri's position in File Number ER-2010-0274, eliminating the immediate need for the language proposed by the company. The Commission is persuaded by Staff's concern that the proposed language would affect the finality of future true-up decisions and would prefer to continue to decide these matter on a case-by-case basis rather than allow Ameren Missouri's tariff to set a standard for all future cases. Therefore, the Commission will decide this issue in favor of Staff and directs Ameren Missouri to strike the disputed language from the tariff.

E. What is the appropriate tariff language to reflect any modifications or clarifications to Ameren Missouri's FAC?

Findings of Fact:

33. This sub-issue is about the choice of one word. In the fuel adjustment portion of the Ameren Missouri's tariff, which is known as a rider, Sheet 98.6 refers to prudence reviews of FAC costs and requires that costs be returned to ratepayers if the Commission determines that the costs were imprudently incurred "or incurred in violation of the terms of this *tariff*" (emphasis added). FN232 Staff would change the word "tariff" in the quoted section to "rider", FN233 reasoning that using the word "tariff" in that manner could be interpreted as a expansion of the true-up to include all other aspects of Ameren Missouri's broader tariff. FN234

FN232. Barnes Rebuttal, Ex. 103, Schedule LMB-ER4.

FN233. Roos Surrebuttal, Ex. 225.

FN234. Transcript, Page 1411, Lines 3-7.

Conclusions of Law:

There are no additional conclusions of law for this sub-issue.

Decision:

The Commission agrees with Staff that the prudence review is limited to matters addressed in this fuel adjustment rider rather than in Ameren Missouri's broader tariff. Therefore, the language proposed by Staff is more precise and shall be adopted.

9. LED Lighting: Should the Commission order Ameren Missouri, not later than twelve (12) months following the effective date of the Report & Order in this case, to complete its evaluation of LED SAL systems, and, based on the results of that evaluation, either file a proposed LED lighting tariff(s) or indicate why such tariff(s) should not be filed?

Findings of Fact:

Introduction:

1. Staff believes that Light Emitting Diode (LED) Street and Area Lighting (SAL) systems are the most energy efficient SAL fixtures currently available and would like Ameren Missouri to take steps to make this form of technology available to its customers. FN235 To that end, Staff asks the Commission to order Ameren Missouri to complete its evaluation of LED SAL systems and within the next year file a proposed LED lighting tariff or provide the Commission with an update on when it will file a proposed LED lighting tariff. FN236

FN235. Staff Report - Rate Design and Class Cost of Service, Ex. 204, Page 34, Lines 1-11.

FN236. Staff Report - Rate Design and Class Cost of Service, Ex. 204, Pages 32-33, Lines 11-22, 1-3.

2. Ameren Missouri is not as enthusiastic about the future of LED lighting. While it intends to continue studying the LED alternative, it does not want the Commission to order it to file an LED tariff at this time. FN237

FN237. Shoff Rebuttal, Ex. 149, Page 4, Lines 1-6.

Specific Findings of Fact:

3. Ameren Missouri currently has approximately 212,800 SAL systems for 1,568 public street and municipal lighting customers in its service territory. Those lights use a total of 137,000 MWh. Most of the existing street lighting in Ameren Missouri's service area uses high-pressure sodium or mercury vapor lamps. FN238

FN238. Staff Report - Rate Design and Class Cost of Service, Ex. 204, Page 33, Lines 5-19.

4. Light Emitting Diodes are composed of a semiconducting chip complete with a junction for electrons to move across. As the electrons move across the junction, they release photons, creating light at very high efficiencies. FN239

FN239. Shoff Rebuttal, Ex. 149, Page 4, Lines 8-12.

5. LED street lighting has certain advantages over other street lighting alternatives including improved efficiency, longer lamp life, improved night visibility, reduced maintenance costs, no mercury, lead, or other known disposal hazards, and it permits the use of programmable controls.FN240

FN240. Staff Report - Rate Design and Class Cost of Service, Ex. 204, Page 34, Lines 1-11.

6. LED street lighting technology is still under development and technical problems remain. At the moment, energy savings benefits do not exceed the cost of the technology.FN241

FN241. Shoff Rebuttal, Ex. 149, Page 7, Lines 14-16.

7. Ameren Missouri is currently working with the Electric Power Research Institute (EPRI) to test and evaluate the potential of currently available LED lighting as part of a national demonstration project. The project started in 2009 and will end sometime in the fourth quarter of 2011.FN242

FN242. Staff Report - Rate Design and Class Cost of Service, Ex. 204, Page 35, Lines 10-17.

8. In the recent Kansas City Power & Light rate case, ER-2010-0355, the Commission approved a stipulation and agreement in which the signatories invited the Commission to host a workshop regarding LED street lighting issues.FN243

FN243. Transcript, Pages 2148-2149.

9. If Ameren Missouri were to offer company-owned LED street lighting under its tariff, it would have to maintain an inventory of LED lighting equipment for which there may be limited demand at a cost to the company and ultimately its ratepayers.FN244

FN244. Cooper Rebuttal, Ex. 134, Page 15, Lines 5-21.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The Commission agrees with Staff that LED street lighting is an exciting technology that should be examined and implemented if appropriate. Staff does not ask the Commission to order Ameren Missouri to immediately file an LED tariff and the Commission will not do so. Instead, Staff asks the Commission to order Ameren Missouri to continue examining the potential of LED lighting and to either file a tariff within one year, or file a status report indicating when it will be able to file such a tariff. Staff's request is reasonable and the Commission will direct Ameren Missouri to either file an LED street lighting tariff by July 31, 2012, or to provide a status report to Staff by that date, indicating when it will be able to file such a tariff.

The Commission emphasizes that Ameren Missouri does not have to file a tariff until it is appropriate to do so. If its further study of the potential of LED street lighting reveals that such lighting will not be a benefit to its customers, Ameren Missouri may inform the Staff of that conclusion in its status report.

10. Solar Rebates Accounting Authority Order (AAO):

A. What is the appropriate method - RESRAM or an Accounting Authority Order (AAO) - for Ameren Missouri to recover the costs it incurs for compliance with the Missouri Renewable Energy Standard (RES) after the true-up date in this case (February 28, 2011)?

Findings of Fact:

Introduction:

1. As explained in more detail in the Conclusions of Law for this issue, Missouri's Renewable Energy Standard law, Section 393.1020, et seq., RSMo (Supp. 2010), requires electric utilities to incur certain costs related to

the adoption of renewable energy technology. Ameren Missouri asks the Commission to grant it an accounting authority order to defer the cost of solar rebates, the cost to purchase renewable energy or renewable energy credits and other related costs incurred after February 28, 2011, the true-up date for this case, until the effective date of new rates in the company's next rate case. FN245

FN245. Weiss Direct, Ex. 130, Page 36, Lines 6-10.

2. Staff does not object to Ameren Missouri's request to defer these costs for later recovery, but contends the company should be required to use a different device known as a Renewable Energy Standard Rate Adjustment Mechanism (RESRAM) for that purpose rather than an Accounting Authority Order (AAO).FN246

FN246. Taylor Rebuttal, Ex. 229, Page 3, Lines 1-9.

Specific Findings of Fact:

3. This is a legal rather than a factual issue and there are no other relevant facts.

Conclusions of Law:

A. Missouri's Renewable Energy Standard (RES) law, found at Sections 393.1020, 1025, and 1030, RSMo (Supp. 2010), require electric utilities, such as Ameren Missouri, to incur certain costs to comply with the requirements of the law.

B. Commission Rule 4 CSR 240-20.100(6) allows an electric utility to file an application and rate schedules to establish a Renewable Energy Standard Rate Adjustment Mechanism (RESRAM) that would allow the utility to recover prudently incurred costs relating to compliance with RES requirements. The regulation allows such an application to be filed either within or outside a general rate proceeding. If it had wished to do so, Ameren Missouri could have applied for a RESRAM in this case.

C. However, Commission Rule 4 CSR 240.20.100(6)(D) specifically offers the electric utility an alternative to the use of a RESRAM. That section of the regulation states:

Alternatively, an electric utility may recover RES compliance costs without the RESRAM procedure through rates established in a general rate proceeding. In the interim between general rate proceedings the electric utility may defer the costs in a regulatory asset account, and monthly calculate a carrying charge on the balance in that regulatory asset account equal to its short-term cost of borrowing. All questions pertaining to rate recovery of the RES compliance costs in a subsequent general rate proceeding will be reserved to that proceeding, including the prudence of the costs for which rate recovery is sought and the period of time over which any costs allowed rate recovery will be amortized. Any rate recovery granted to RES compliance costs under this alternative approach will be fully subject to the retail rate impact requirements set forth in section (5) of this rule.

This section of the regulation describes exactly the alternative approach that Ameren Missouri has chosen to pursue in this rate case.

D. Ameren Missouri's decision to request an AAO in this case instead of the RESRAM that Staff would prefer it to have is in full compliance with the provisions of the Commission's rule.

E. In its reply brief, Staff sets forth an argument that Ameren Missouri's use of an AAO will allow it to recover a greater amount of carrying costs than if it were required to use a RESRAM.FN247 Staff's argument is not supported by any testimony or other evidence in the record, and furthermore it is irrelevant. The Commission's rule specifically allows Ameren Missouri to use an AAO to defer recovery of its costs as an alternative to recovering those costs through a RESRAM. Presumably, Ameren Missouri chose to use the recovery method that was most favorable to it, as it is allowed to do by the regulation. If Staff does not like the alternative allowed by the regulation, it can ask the Commission to change the regulation, but for purposes of this case, the Commission is bound by that regulation and cannot deny Ameren Missouri the use of its chosen alternative.

FN247. Staff's Reply Brief, Pages 64-65.

Decision:

Ameren Missouri may defer its RES compliance costs through an Accounting Authority Order as permitted by Commission Rule 4 CSR 240-20.100(6)(D).

B. If the Commission determines that an AAO is appropriate, should the Company be authorized in this case to implement an AAO to recover the costs it incurred for compliance with the RES before the true-up date in this case?

C. What amount of solar rebate costs should Ameren Missouri be allowed to include in the revenue requirement used to set rates in this case?

Findings of Fact:

Introduction:

1. This issue concerns the amount of RES compliance costs that Ameren Missouri should be allowed to recover in this case and means by which it should to allowed to recover those costs.

2. The renewable energy portfolio requirements of the RES law are still rather new and Ameren Missouri has not yet incurred many of the costs that it may ultimately have under that law. For purposes of this case, the only RES compliance costs in question are the cost of solar rebates paid by Ameren Missouri to its customers who have installed or expanded solar electric systems on the customer's premises.

3. Staff and Ameren Missouri agree that those solar rebate costs should be treated as an expense item and immediately recovered as an on-going operations and maintenance cost.FN248 MIEC contends the solar rebate costs should be amortized over a period of ten years. FN249

FN248. Weiss Rebuttal, Ex. 131, Page 16, Lines 2-6.

FN249. Brubaker Direct, Ex. 403, Page 20, Lines 8-9.

4. Although they agree that the solar rebate costs should be expensed rather than amortized, Staff and Ameren Missouri disagree about the amount that Ameren Missouri should be allowed to recover.

Specific Findings of Fact:

5. MIEC's witness, Maurice Brubaker, argues that the company's expense of paying the solar rebates should be amortized over ten years to reflect the minimum ten year expected life of the installed solar equipment. FN250 He reasons that the company and its ratepayers will benefit from the equipment for at least ten years and therefore the costs that make that benefit possible should be recovered over ten years.

FN250. Brubaker Direct, Ex. 403, Pages 19-20.

6. Ameren Missouri does not own or operate the solar equipment for which it is required to pay a rebate. That equipment is the property of the customer who has sole control and responsibility for them and will primarily benefit from the use of the equipment.FN251 Thus, to Ameren Missouri, payment of the solar rebates is simply an expense imposed upon it by the statute. For that reason, a long amortization period as proposed by MIEC is inappropriate.

FN251. Weiss Rebuttal, Ex. 131, Page 17, Liens 6-7.

7. The other half of this issue concerns the amount that Ameren Missouri should be allowed to recover for past solar rebate payments and how much should be included in rates as a going-forward expense.

8. In the 2010 calendar year, Ameren Missouri incurred $487,782 in solar rebate costs. Staff would allow Ameren Missouri to include that amount in rates on a going forward basis.FN252 During the twelve months ending on the true-up date of February 28, 2011, Ameren Mis-

souri incurred $885,266 in solar rebate costs. Ameren Missouri asks the Commission to include that amount in rates on a going forward basis.FN253

FN252. Transcript, Page 2192, Lines 1-4.

FN253. Weiss True-Up Direct, Ex. 174, Schedule GSW-TE18-110.

9. The fact that solar rebate costs are substantially higher for the twelve months ending at the February 28, 2011 true-up date than they were for the 2010 calendar year indicates that such costs are increasing. For that reason, Ameren Missouri's actual expenses through the true-up period are a better indicator of the amount of expenses the company will likely incur going forward and forward looking rates should be based on that amount.

10. Another aspect of this issue concerns whether Ameren Missouri should be permitted to accumulate in its AAO the solar rebates paid from the beginning of the program until the new rates become effective in this case.

11. The treatment of its solar rebate expenses proposed by Ameren Missouri is appropriate because the company started to incur those expenses after the company's last rate case and therefore those expenses were not reflected in the rates established in that case. The recovery of those costs and the others deferred in the AAO will then be decided in the next rate case.FN254

FN254. Weiss Rebuttal, Ex. 131, Page 16, Lines 13-23.

12. Staff suggests that those costs should not be accumulated in the AAO but should instead be recovered in this rate case. But Staff does not offer a specific recommendation about how that recovery should be accomplished.

13. The Commission finds that Ameren Missouri shall accumulate the amount it has paid for solar rebates from the beginning of the program until new rates become effective in this case. The recovery of those costs and future costs deferred in the AAO will be decided in Ameren Missouri's next rate case.

Conclusions of Law

A. Ameren Missouri has paid rebates to its customer who have installed or expanded solar power equipment pursuant to Section 393.1030.3, RSMo (Supp. 2010), which requires electric utilities to: “make available to its retail customers a standard rebate offer of at least two dollars per installed watt for new or expanded solar electric systems sited on customers' premises, up to a maximum of twenty-five kilowatts per system, that become operational after 2009.”

B. Staff argues that Ameren Missouri's solar rebate expenses for the 2010 calendar year should be used to establish the company's rates going forward because Commission Rule 4 CSR 240-20.100(5)(A) requires that the retail rate impact for purposes of determining whether the 1 percent cap has been exceeded is to be “calculated on an incremental basis for each planning year …”. However, the regulations requirement for the use of a planning year to calculate retail rate impact does not mean that the Commission must also use a planning year to determine an appropriate amount of expense to include in rates on a going forward basis.

Decision:

Ameren Missouri shall include $885,266 in its rates for ongoing solar rebate expenses. Ameren Missouri shall accumulate in an AAO the amount it has paid for solar rebates from the beginning of the program until new rates become effective in this case. The recovery of those costs and future costs deferred in the AAO will be decided in Ameren Missouri's next rate case.

11. Union Issues:

A. Does the Commission have the authority to order Ameren Missouri to do the following:

(1) Institute or expand its training programs within specified time periods as a means of investing in its employee infrastructure?

(2) Hire specific additional personnel within specified time periods as a means of investing in its employee infrastructure?

(3) Submit to a tracker for its energy delivery distribution system?

(4) Submit to a tracker to address the need and efforts to replace the aging workforce?

(5) Expend a substantial portion of the rate increase from this proceeding on investing and re-investing in its regular employee base in general, including hiring, training and utilizing its internal workforce to maintain its normal and sustained workload?

(6) Use a portion of the rate increase from this proceeding to replace equipment, wires and cable which have out lived their anticipated life?

B. If the Commission does have the authority, should it order Ameren Missouri to take one or more of the steps listed above?

Findings of Fact:

Introduction:

1. The various unions that represent some of Ameren Missouri's employees appeared at the hearing to support the company's request for a rate increase. However, they asked the Commission to order Ameren Missouri to spend more money on employee training and to take specific steps to increase its internal workforce so that it will use fewer outside contractors and to replace an aging workforce. The Unions also ask the Commission to order Ameren Missouri to spend more money to replace aging infrastructure. Ameren Missouri contends it is currently providing safe and adequate service and argues the Commission has no authority to manage the day-to-day affairs of the company.

Findings of Fact:

2. Michael Walter is the Business Manager of International Brotherhood of Electrical Workers Local 1439, AFL-CIO.[FN255] He testified that he is concerned about Ameren Missouri's ability to deal with an aging infrastructure and an aging workforce.[FN256] I n particular, he is concerned that Ameren Missouri has not spent enough on training new workers and as a result has over-relied on outside contractors to perform normal and sustained work.[FN257] In particular, Walter is concerned that Ameren Missouri's trained work force is aging and he sees a need for increased training of new workers capable of stepping in when the current workforce retires.[FN258] He asks the Commission to require Ameren Missouri to spend a portion of its rate increase to improve training and increase the portion of the workload performed by its internal workforce.[FN259]

FN255. Walter Direct, Ex. 650, Page 3, Lines 3-4.

FN256. Walter Direct, Ex. 650, Page 3, Lines 25-26.

FN257. Walter Direct, Ex. 650, Pages 5-8.

FN258. Walter Direct, Ex. 650, Page 4.

FN259. Walter Direct, Ex.650, Pages 7, Lines 28-43.

3. In response to the concerns expressed by the Unions, Commissioner Davis asked Ameren Missouri's witnesses if the company could use extra money for training of its work force. The witness replied that additional money could be used to institute a heavy underground apprentice program.[FN260] Heavy underground training involves industrial type routing of underground electric lines in the downtown area.[FN261] The witness testified that $1,250,000 would be needed for that purpose and explained that that amount would buy needed equipment and would be sufficient to hire nine new journeymen, a supervisor, and a trainer.[FN262]

FN260. Transcript, Page 2306, Lines 3-17.

FN261. Transcript, Page 2278, Lines 15-18.

FN262. Transcript, Page 2307-2308.

4. The Commission finds that the evidence presented by the union witnesses does not demonstrate that Ameren Missouri has failed to supply safe and adequate service to the public. Furthermore, for reasons fully explained in its Conclusions of Law, the Commission does not have the authority to dictate the manner in which Ameren Missouri conducts its business. Therefore, the Commission will not attempt to dictate to the company regarding its use of outside contractors.

5. However, the union witnesses and Ameren Missouri agree that there is a need for improved training. On that basis, the Commission finds that there is a need for additional training to meet the need for skilled heavy underground workers.

6. Therefore, the Commission will add $1.25 million to Ameren Missouri's cost of service to fund increased training staff.

7. The Commission wants to ensure that all parties are satisfied that the additional training money authorized by this order is well spent. Therefore, the Commission will create a Training Advisory Group initially including Ameren Missouri, the Unions, Staff, and Public Counsel. Other entities may also participate if they wish to do so. The Training Advisory Group will provide input to Ameren Missouri on the design, implementation, and evaluation of the company's additional training programs authorized under this and previous rate case orders. If the Training Advisory Group is unable to reach agreement on any issue related to the training programs, any member may petition the Commission for further direction.

8. The Unions also ask the Commission to require the company to compile information about its aging electric distribution system and its aging workforce and to submit periodic reports to the Commission's Staff. The Unions did not present any detailed evidence about the information that would be contained in such reports, nor did they demonstrate any need for such reports. The Commission's Staff is able to obtain any information it may want or need from the company without the need and expense of creating any additional reporting requirements.

Conclusions of Law:

A. The Commission has the authority to regulate Ameren Missouri, including the authority to ensure that the utility provides safe and adequate service. However, the Commission does not have authority to manage the company. In the words of the Missouri Court of Appeals,

The powers of regulation delegated to the Commission are comprehensive and extend to every conceivable source of corporate malfeasance. Those powers do not, however, clothe the Commission with the general power of management incident to ownership. The utility retains the lawful right to manage its own affairs and conduct its business as it may choose, as long as it performs its legal duty, complies with lawful regulation, and does no harm to public welfare.FN263

FN263.*State ex rel. Harline v. Public Serv. Com'n*, 343 S.W.2d 177, 182 (Mo. App. 1960)

Therefore, the Commission does not have the authority to dictate to the company whether it must use internal workforce rather than outside contractors to perform the work of the company, nor does the Commission have the authority to direct the company to spend a portion of the rate increase to replace specific items of equipment.

Decision:

The evidence presented by the union does not demonstrate that Ameren Missouri has failed to provide safe and adequate service and the Commission will not dictate to the company whether it must use its internal workforce or outside contractors to perform the company's work. However, the Commission will add $1,250,000 to Ameren Missouri's cost of service to fund increased training for heavy underground work.

12. Property Tax:

A. What amount of property tax expense relating to the Sioux Scrubbers and the Taum Sauk additions the Company seeks to put in rate base in this case

should the Commission include in Ameren Missouri's revenue requirement for ratemaking purposes?

Findings of Fact:

Introduction:

1. Ameren Missouri pays property taxes on property it owns in Missouri, Illinois, and Iowa.[FN264] In a stipulation and agreement that the Commission approved in this case, the parties agreed that Ameren Missouri's revenue requirement in this case would include at least $119 million for payment of such property taxes, based on the amount of property taxes the company paid in 2010.[FN265] That stipulation and agreement however excluded from the settlement additional property taxes related to the Sioux scrubber and Taum Sauk plant additions. Ameren Missouri and Staff propose to allow the company to include an additional $10 million in its revenue requirement for those additional property taxes. MIEC proposes to disallow $2.5 million of additional property taxes associated with the Taum Sauk rebuild and $7.5 million associated with the addition of the Sioux Scrubbers.[FN266] That is the basis for this issue.

FN264. Transcript, Page 1285, Lines 23-25.

FN265. First Nonunanimous Stipulation and Agreement - Miscellaneous Revenue Requirement Items, filed May 3, 2011.

FN266. Meyer Direct, Ex. 400, Page 16, Lines 1-6.

2. The Sioux scrubber and the Taum Sauk plant additions went into service in 2010. That means they became subject to the state of Missouri's property tax assessment in 2011. Property tax on property owned on January 1 must be paid by December 31 of the same year.[FN267] That means Ameren Missouri will not pay the additional property tax associated with the Sioux scrubber and the Taum Sauk plant additions until December 31, 2011, ten months after the close of the true-up period for this case.

FN267. Weiss Rebuttal, Ex. 131, Page 2, Lines 18-23.

3. At this point Ameren Missouri cannot know the exact amount of additional taxes it will owe for the Sioux scrubber and the Taum Sauk plant additions because it has not yet received tax bills from the various county assessors. It will not receive those tax bills until September, October, and November.[FN268]

FN268. Transcript, Page 1306, Lines 5-10.

4. Before the Sioux scrubber and the Taum Sauk additions were put in service they were subject to property tax as construction work in progress. For regulatory accounting purposes, property taxes on construction work in progress is removed from the company's expenses and instead treated as a capital item that the company recovers through depreciation over the life of the plant.[FN269] Since the Sioux scrubber and the Taum Sauk additions were still treated as construction work in progress for purposes of the 2010 tax assessments, they were not included in the company's $119 million property tax bill for 2010 for regulatory purposes. Thus, the Sioux scrubber and the Taum Sauk additions will be entirely new taxed items for purposes of determining the amount of Ameren Missouri's property tax bill that can be recovered as an expense.

FN269. Transcript, Page 1321, Lines 13-20.

5. Generally accepted accounting principles (GAAP) require Ameren Missouri to begin accruing its 2011 tax liabilities on its books at the beginning of the year. Thus, by December 31, 2011, the company will have expensed its entire 2011 tax payments.[FN270]

FN270. Transcript, Page 1319, Lines 17-19.

6. The amount Ameren Missouri expenses for taxes under the GAAP requirements is based on plant investment on January 1. Average tax rates from 2010, adjusted for estimated changes in tax rates for 2011, are applied to the plant investment amount to determine estimated total taxes for 2011. Ameren Missouri's Manager of Regulatory Accounting, Gary Weiss, testified that that amount is usually fairly accurate.[FN271] That is

the same method that Staff and Ameren Missouri used to calculate 2011 taxes for this case.FN272

FN271. Transcript, Page 1323, Lines 7-18.

FN272. Weiss Rebuttal, Ex. 131, Lines 15-22.

7. As a general principle, expenses must be known and measurable before a utility will be allowed to recover those expenses in rates. That does not mean an expense must be known precisely to be included in rates. For example, on this very issue, the parties agreed that Ameren Missouri's tax expenses to be included in going forward rates would be based on the company's 2010 tax bill, even though it is apparent that those taxes may change in future years.

8. MIEC questioned Ameren Missouri's witness, Gary Weiss, about a document from his work papers pertaining to the Sioux scrubber. That document contained the following disclaimer: “We cannot determine with accuracy the anticipated 2011 property taxes pertaining to the Sioux scrubber since the accounts involved are state assessed property.” FN273MIEC contends that this disclaimer is an admission by Ameren Missouri that the 2011 property taxes in question are not known and measurable, and thus not recoverable.

FN273. Ex. 415.

9. However, Weiss explained that the document that includes the disclaimer was created in early 2010. Ameren Missouri property tax department added the disclaimer at a time when the company did not yet have the 2010 assessment and tax rates. He testified that the company now has the January 1, 2011 assessment and actual taxes paid in 2010. As a result, he is now confident in the company's estimate of 2011 taxes.FN274The Commission finds that the disclaimer on the document is not dispositive of this issue.

FN274. Transcript, Page 1324, Lines 5-16.

10. In considering what expense should be treated as known and measureable, it is important to keep in mind the underlying purpose of the Commission's ratemaking process. The Commission is not setting rates designed to allow the company to recover past expenses. Rather, the Commission is using historical cost data based on a test year to determine a just and reasonable going-forward rate that will afford the company a reasonable opportunity to recover its costs and earn a profit.

11. It is known that Ameren Missouri will pay additional property tax now that the Sioux scrubbers and the Taum Sauk additions are in service and have been assessed for tax purposes. Ameren Missouri is already accruing those taxes on its books and has reasonably determined the amount accrued based on the known value of the property and adjusted 2010 tax rates. For purposes of determining a reasonable rate, the Commission finds that the additional taxes Ameren Missouri will pay for the Sioux scrubbers and the Taum Sauk additions are known and measurable. The additional $10 million in property tax expenses associated with those additions shall be included in the company's revenue requirement.

Conclusions of Law:

A. Missouri Retailers Association argues that Ameren Missouri's property taxes attributable to the Taum Sauk additions are not known and measureable because the local taxing authority may have to decrease its tax levy based on the increased valuation of the property under Section 137.073.2, RSMo 2000. However, that statute provides that a levy rollback is not required when the increased valuation results from “new construction and improvements.” Thus, the levy rollback provision would not apply to the Taum Sauk addition.FN275

FN275. Transcript, Page 1293, Lines 12-21.

Decision:

The additional $10 million in property tax expenses associated with the Sioux scrubbers and the Taum Sauk additions shall be included in the company's revenue requirement.

B. Should the Commission order Ameren Missouri to return to its customers any reductions that the Company receives in its 2010 property taxes?

Findings of Fact:

12. Ameren Missouri has appealed a portion of its 2010 state property taxes to the State Tax Commission. The company has paid the full amount of those taxes, but $28,883,742 of that payment is being held in escrow pending the results of the appeal.FN276 If Ameren Missouri prevails on its appeal, its 2010 taxes, as well as future tax bills could be reduced by an unknown amount. No hearing date has yet been set on the tax appeal. FN277

FN276. Staff Report - Revenue Requirement / Cost of Service, Ex. 201, Page 91, Lines 10-13.

FN277. Transcript, Page 1315, Lines 13-15.

13. Ameren Missouri has agreed to track any possible tax refunds. Staff asks the Commission to order Ameren Missouri in this case to credit any tax refund it ultimately receives to its ratepayers. Ameren Missouri contends the Commission should not issue such an order in this case and should instead simply allow the company to track the refund and wait until a future case to determine how any refund received should be handled.

Specific Findings of Fact:

14. The only question before the Commission at this time is whether to order Ameren Missouri in this case to return any tax refund it may receive to its customers. There is no disagreement about Ameren Missouri's duty to track that refund. If Ameren Missouri does receive a tax refund, then the Commission would certainly expect that the company would return that refund to its customers who are ultimately paying the tax bill. It is hard to imagine any circumstance in which such a refund would not be ordered. However, such an order must wait until a future rate case in which that decision will be presented to the Commission.

15. Any such order the Commission could issue in this case would be ineffective, as this Commission cannot bind a future Commission. At this time, the Commission can only order Ameren Missouri to track any possible refund. A decision about how any such tax refund is to be handled must be left to a future rate case.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

Ameren Missouri shall track any state tax refund it receives because of its appeal of its 2010 assessment. The Commission will decide in a future rate case how any such refunds are to be handled.

13. Rate Design/Class Cost of Service

A. Class Cost of Service:

(1) Which of the proposed class cost of service methodologies - the 4 NCPA&E methodology, the Base Intermediate-Peak methodology, or the 4P-P&A methodology - should the Commission use in this case to allocate Ameren Missouri's investment and costs among the Company's various rate classes?

(2) What methodology should the Commission use in this case to allocate Ameren Missouri's fixed production plant investment and operation and maintenance costs?

B. Rate Design:

(1) To what extent should the Commission rely on the results of a class cost of service study in apportioning revenue responsibility among Ameren Missouri's customer classes in this case?

(2) What amount of increase or decrease in the revenue responsibilities of Ameren Missouri's customer classes should the Commission order in this case?

Findings of Fact:

Introduction:

1. After the Commission determines the amount of rate increase that is necessary, it must decide how that rate increase will be spread among Ameren Missouri's customer classes. The basic principle guiding that decision is that the customer class that causes a cost should pay that cost.

2. During the course of the hearing, Public Counsel, MIEC, AARP, the Consumers Council, MEUA, MEG, and the Missouri Retailers Association filed a nonunanimous stipulation and agreement that reached an agreement on how the rate increase should be allocated to the customer classes. Ameren Missouri and Staff did not sign the stipulation and agreement but do not oppose the compromise agreement. The Municipal Group, however, does oppose that stipulation and agreement.

3. Because of that opposition, the Commission cannot approve the stipulation and agreement. Nevertheless, all signatory parties testified that they continue to support the compromise described in the stipulation and agreement. That stipulation and agreement continues to represent the position of the signatory parties and the Commission can consider that position as it decides this issue.

4. Ameren Missouri has seven customer classes.[FN278] The Residential class is comprised of residential households. The Small General Service and Large General Service classes are comprised of commercial operations of various sizes. The first three classes receive electric service at a low secondary voltage level. The Small Primary Service and the Large Primary Service are larger industrial operations that receive their electric service at a high voltage level. The Large Transmission Service class takes service at a transmission voltage level. Noranda Aluminum is the only member of the Large Transmission Service class. The seventh customer class is the Lighting Service class, which includes area and street lighting.

FN278. Cooper Direct, Ex. 133, Page 4, Lines 4-18.

Specific Findings of Fact:

5. To evaluate how best to allocate costs among these customer classes, four parties prepared and presented class cost of service studies. The studies presented by Ameren Missouri and MIEC used versions of the Average and Excess Demand Allocation method (A&E). Staff used a Base, Intermediate, Peak (BIP) method, and Public Counsel used a Peak and Average Demand Allocation method.

6. The following chart compares the results of each of the class cost of service studies, indicating the percent change in class revenues required to equalize class rates of return, as well as the dollar amounts needed to bring a class to its indicated cost of service. A negative number means the class is paying more than its indicated share of costs. A positive number means the class is paying less than its indicated share. All dollar figures are in millions.

Study	Residential	Small General Service	Large General Service	Large Primary Service	Large Transmission Service	Lighting
Staff[279]	13.21% $144.6	-1.78% $(5.0)	-8.52% ($60.4)	-6.42% ($11.5)	-1.64% $(2.3)	21.02% $6.6
Ameren Missouri[280]	6.95% $76.0	-8.77% ($24.6)	-8.94% ($63.7)	-1.42% ($2.6)	5.60% $7.8	22.41% $7.0
OPC[281]	3.12% $34.1	-11.22% ($31.4)	-5.69% ($40.4)	6.34% $11.3	18.85% $26.3	
MIEC[282]	9.7% $106.0	-7.3% ($20.5)	-10.4%	-6.7% ($12.2)	-5.0% ($6.9)	24.9% $7.7

($74.3)

279. Staff Report - Rate Design and Class Cost of Service, Ex. 204, Page 3, Table 1.

280. Ex. 551.

281. Kind Direct, Ex. 301, Attachment A.

282. Brubaker Direct, Ex. 404, Schedule MEB-COS-5.

For example, Staff's study indicated the Residential class is currently paying $144.6 million less than Ameren Missouri's cost to serve that class. In contrast, according to Staff's study, the Large General Service class is currently paying $60.4 million more than Ameren Missouri's cost to serve that class. Although the exact numbers vary among the various studies, all the studies agree that the Residential class is currently paying substantially less than its cost of service and that the other classes are currently paying more than their cost of service.

7. The studies presented by Staff, Ameren Missouri and MIEC show that the Large Transmission Class is currently paying rates that are near its current cost of service. Public Counsel's study however shows the Large Transmission Class as paying 18.83 percent less than its cost of service. However, Public Counsel's study uses an Average and Peak allocation method that the Commission has rejected as unreliable in previous cases. FN283

FN283.*In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, File Number ER-2010-0036, Report and Order, May 28, 2010, Page 85.

8. Noranda Aluminum, which is the sole member of the Large Transmission Class, runs its aluminum smelter at a constant rate, 24 hours a day, 7 days a week. Therefore, its usage of electricity does not vary significantly by hour or by season. Thus, while it uses a lot of electricity, that usage does not cause demand on the system to hit peaks for which the utility must build or acquire additional capacity. Another customer class, for example, the residential class, will contribute to the average amount of electricity used on the system, but it will also contribute a great deal to the peaks on system usage, as residential usage will tend to vary a great deal from season to season, day to day, and hour to hour.

9. To recognize that pattern of usage, the Average and Excess method used by Ameren Missouri and MIEC in their studies separately allocates energy cost based on the average usage of the system by the various customer classes. It then allocates the excess of the system peaks to the various customer classes by a measure of that class' contribution to the peak. In other words, the average and excess costs are each allocated to the customer classes once.

10. The Peak and Average method, in contrast, initially allocates average costs to each class, but then, instead of allocating just the excess of the peak usage period to the various cost causing classes, the method reallocates the entire peak usage to the classes that contribute to the peak. Thus, the classes that contribute a large amount to the average usage of the system but add little to the peak, have their average usage allocated to them a second time. Thus, the Peak and Average method double counts the average system usage, and for that reason is unreliable.FN284 In particular, it tends to overstate the class revenue responsibility of the Large Transmission Class and therefore Public Counsel's finding that that class is significantly under contributing is especially unreliable.

FN284. Brubaker Rebuttal, Ex. 405, Pages 4-6.

11. In general, it is important that each customer class carry its own weight by paying rates sufficient to cover the cost to serve that class. That is a matter of simple

fairness in that one customer class should not be required to subsidize another. Requiring each customer class to cover its actual cost of service also encourages cost effective utilization of electricity by customers by sending correct price signals to those customers.FN285 However, the Commission is not required to precisely set rates to match the indicated class cost of service. Instead, the Commission has a great deal of discretion to set just and reasonable rates, and can take into account other factors, such as public acceptance, rate stability, and revenue stability in setting rates.

FN285. Cooper Direct, Ex. 133, Page 17, Lines 1-12.

12. Ameren Missouri proposed that any rate increase should be allotted equally to each customer class. In other words, each class would receive the system average percentage increase.FN286 That would leave the existing disparities revealed in the class cost of service studies unchanged.

FN286. Cooper Direct, Ex. 133, Page 19, Lines 1-2.

13. Staff proposed that small adjustments be made to shift revenue responsibility from the classes that are paying more than their share to those that are paying too little. Specifically, Staff recommends that the Residential and Lighting classes receive the system average percentage increase plus one percent. The Large General Service / Small Primary Service classes would receive no increase for the first $30 million in increased rates and the system average thereafter. Finally, Staff would have the Commission give the Small General Service and Large Transmission Service classes the system average increase.FN287

FN287. Staff Report -Class Cost-of-Service and Rate Design, Ex. 204, Page 1, Lines 2-20.

14. MIEC proposed that the Residential and Lighting classes receive a revenueneutral increase with the other classes receiving decreases to bring each class closer to its actual cost of service.FN288

FN288. Brubaker Direct, Ex. 404, Schedule MEB-COS-6.

15. Finally, Public Counsel recommended that the Commission make no adjustment to the residential class but proposed revenue neutral shifts sufficient to move each other class' revenues half-way toward that class' cost of service.FN289

FN289. Kind Direct, Ex. 301, Page 7, Lines 6-22.

16. The stipulation and agreement to which the Municipal Group objected would shift revenue responsibility to the Residential and Lighting classes in the following manner:

Rate Class	Current Revenues	Revenue Increase	Percent Change
Residential	$1,099,447,000	$21,989,000	+2.00%
Small Gen. Service	$278,880,000	($4,957,000)	-1.78%
Large Gen. Service / Small Primary	$710,244,000	($12,624,000)	-1.78%
Large Primary	$178,643,000	($3,175,000)	-1.78%
Large Transmission	$139,472,000	($2,479,000)	-1.78%
MSD	$64,000		0.00%
Lighting	$31,171,000	$1,247,000	+4.00%

In other words, the Residential class' rates would increase by 2 percent on a revenue-neutral basis and the Lighting class' rates would increase by 4 percent on a revenue-neutral basis. All other classes would see their rates decline by 1.78 percent on a revenue-neutral basis.

17. The stipulation and agreement, now the joint position of the signatory parties, further provides that any overall increase granted to Ameren Missouri as a result of this rate case would be implemented on an equal percent, across-the-board basis and added to the described revenue-neutral adjustments to determine each class' total increase relative to current rates.

18. The stipulation and agreement, now the joint position, also provides that no class should receive an overall rate decrease if any other class is receiving an overall rate increase. In such a circumstance, the class receiving that decrease would be held at its current rates with the avoided decrease spread equally among the remaining classes receiving revenue-neutral decreases.

19. The reallocation of revenue responsibility the signatories agreed to in the stipulation and agreement, now their joint position, bears some resemblance to the results of all the submitted class cost of service studies. Most notably, all the submitted studies indicate that the residential class is paying substantially less than its actual revenue responsibility. The stipulated position would bring that revenue class closer to its actual cost of service.

20. The party that objected to the stipulation and agreement, the Municipal Group, represents the members of the Lighting class, which would receive a 4 percent revenue-neutral increase under the stipulation and agreement. Understandably, the Municipal Group would prefer a system average across-the-board increase as proposed by Ameren Missouri. However, there are circumstances that justify a larger than average increase for the Lighting class.

21. In Ameren Missouri's last rate case, ER-2010-0036, the Municipal Group complained that neither Ameren Missouri, nor any other party had performed a class cost of service study that would determine the reasonableness of the rate charged to the Lighting class. For many years, Ameren Missouri and the other parties to its rate cases had ignored the Lighting class in their studies because of its insignificant size compared to Ameren Missouri's over-all customer base. As a result, the Commission found that the Lighting class had been given rates that "may or may not bear any resemblance to the cost to serve that class." [FN290] On that basis, the Commission exempted the Lighting class from the rate increase that resulted from that Report and Order and directed Ameren Missouri to include the Lighting class in its next class cost of service study.

FN290. *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, File Number ER-2010-0036, Report and Order, May 28, 2010, Page 99.

22. Ameren Missouri and the other parties included the Lighting class in their class cost of service studies for this case and those studies indicate that the Lighting class is not currently paying its full cost of service. According to Staff's study, the Lighting class' rates would have to be increased 21.02 percent to bring in sufficient revenue from that class to cover the cost to serve that class. Ameren Missouri's study sets the necessary increase at 22.41 percent, and MIEC's study was even higher at 24.9 percent. Considering the results of those studies, the 4 percent revenue-neutral increase allotted to the Lighting class by the stipulation and agreement / joint position is quite reasonable.

Conclusions of Law:

A. Commission Rule 4 CSR 240-2.115(2)(D) provides that a nonunanimous stipulation and agreement to which an objection is made is to be treated as a joint position of the signatory parties, except that no party is bound by the agreement.

B. The approach the Commission must take when considering a nonunanimous stipulation and agreement to which an objection is made is further described in a 1982 decision of the Missouri Court of Appeals. In

State ex rel. Fischer v. Public Service Commission, FN291 the Court held that when considering a nonunanimous stipulation and agreement the Commission must recognize all statutory requirements, including the right to be heard and to introduce evidence. Furthermore, the Commission's decision must be in writing and must include adequate findings of fact.

FN291.645 S.W.2d 39 (Mo. App. W.D. 1982)

Decision:

The Commission accepts the joint position advocated by the parties representing the vast majority of Ameren Missouri's customers and accepted by Ameren Missouri and Staff. The Commission's acceptance of that joint position will result in a reasonable adjustment of rates to bring all parties closer to their actual cost of service.

(3) What is the appropriate monthly residential customer charge that should be set for Ameren Missouri in this case?

Findings of Fact:

Introduction:

23. The monthly residential customer charge is the portion of the customer's bill that is independent of the amount of electricity used in the month. It is the amount the customer must pay just to remain a customer of Ameren Missouri. In general, consumer groups prefer a low customer charge reasoning that customers want to be able to lower their costs if they use less electricity. The utility, including Ameren Missouri, prefers a higher customer charge because the customer charge allows the company to recover its fixed costs with more certainty regardless of how much electricity the customer uses in a month. Currently Ameren Missouri's monthly residential customer charge is set at $8.00.

Specific Findings of Fact:

24. The various class cost of service studies examine the amount of charges that should appropriately be collected from customers through the fixed monthly customer charge. Ameren Missouri indicates its study would support a residential customer charge of approximately $18. However, Ameren Missouri's witness recommended that the customer charge be increased only to $10. FN292

FN292. Cooper Rebuttal, Ex. 134, Page 11, Lines 1-7.

25. Staff's witness indicated his class cost of service study would support a monthly customer charge of $9.67, but he recommended the customer charge be increased to only $9.00 to avoid a large impact on residential customers. FN293

FN293. Staff Report - Rate Design and Class Cost of Service, Ex. 204, Pages 19-20, Lines 33-36, 1-3.

26. The nonunanimous stipulation and agreement on class cost of service issues provides that the residential customer charge would remain at $8.00, with the remaining revenue assigned to the residential class to be allocated to volumetric charges.

27. Although the Municipal Group objected to the stipulation and agreement, the stipulation and agreement still represents the joint position of the signatory parties. Despite their earlier positions advocating an increase in the customer charge, neither Ameren Missouri nor Staff raised any objection to the stipulation and agreement. Furthermore, although the Municipal Group objected to the stipulation and agreement as a whole, it expressed no opposition to the agreement to leave the residential customer charge at $8.00.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The current residential customer charge of $8.00 per month is reasonable and shall be continued.

(4) Should AmerenMO be required to eliminate declining block rates for the residential winter energy charge? If so, should the declining block rates be eliminated in a revenue neutral manner?

Findings of Fact:

Introduction:

28. Ameren Missouri's current residential rate design includes a declining block element for the winter billing season only. That means that during the winter the rate paid for electricity goes down as more electricity is used. That declining block design benefits customer who use a lot of electricity in the winter, chiefly customers who use electricity for space heating in their home. That design also benefits the electric utility in that it makes electricity more competitive with other fuel sources for space heating and allows the company to sell more electricity during off-peak times.

Specific Findings of Fact:

29. A stipulation and agreement approved in Ameren Missouri's last rate case, ER- 20100036, required Ameren Missouri to conduct a study addressing the elimination of declining block rates for residential service in a revenue neutral manner and to file the results of that study in this, its next rate case. Ameren Missouri conducted that study and reported the results in the direct testimony of Wilbon Cooper.FN294

FN294. Cooper Direct, Ex. 133, Pages 25-26.

30. Ameren Missouri reports that the elimination of the declining block rate would increase the electric bill for customers who use electricity for space heating by roughly five percent above the overall average rate increase that would otherwise result from this case.FN295 If the declining block rate design were eliminated and Ameren Missouri were allowed to increase its overall rates by 10.8 percent, monthly winter bills would decrease by $1.78 per month at 700 kWh, increase by $53.85 per month at 4,000 kWh, and increase by $157.05 per month at 10,000 kWh from current rate levels. For comparison, if the same overall rate increase were allowed and the declining block rate were retained, the monthly winter bills would increase $6.20 per month at 700 kWh, $17.88 per month at 4,000 kWh, and $38.88 per month at 10,000 kWh.FN296

FN295. Cooper Direct, Ex. 133, Page 25, Lines 20-23.

FN296. Cooper Direct, Ex. 133, Page 26, Lines 2-7.

31. The Missouri Department of Natural Resources asks the Commission to eliminate the declining block rates to encourage energy efficiency and conservation, arguing that declining block rates do not send a signal to encourage reduced usage.FN297

FN297. Wolfe Rebuttal, Ex. 801, Page 16, Lines 16-21.

32. Customers who use less than approximately 1,400 kWh per month would see their monthly bill decrease if the declining block rate was eliminated. Those who use more than 1,400 kWh per month would see their monthly bill increase.FN298 An average residential customer uses approximately 1,000 to 1,100 kWh per month.FN299 As a result, the customers who would see increased monthly bill would chiefly be those who use electricity for space heating. FN300

FN298. Transcript, Page 2385, Lines 13-21.

FN299. Transcript, Page 2386, Lines 5-6.

FN300. Transcript, Page 2393, Lines 2-6.

33. There is no evidence in the record to indicate how a phase-in of the elimination of declining block rates could be accomplished.FN301

FN301. Transcript, Page 2402, Lines 13-18.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The Commission does not like declining block rates. They do not send a proper price signal and tend to encourage the excessive consumption of electricity. In addition, declining block rates may force residential customers who conserve electricity to subsidize their neighbors who use excessive amounts.

In the last case a stipulation and agreement required Ameren Missouri to study the elimination of declining block rates. Not surprisingly, Ameren Missouri's study concluded that elimination of the declining block rate would cost the company money and would result in increased rates for the customers who currently benefit from the rate. MDNR is the only party that responded to Ameren Missouri's study, but that response dealt only in generalities and provided very little detailed information to assist the Commission in actually evaluating the merits of the elimination of the winter declining block rate.

Unfortunately, there is just not enough evidence in this record to justify a modification of the current rate design. The only thing that is clear is that the elimination of the declining block rate would have an unfortunate impact on the rates of those customers who use electricity for space heating. If any party wants to try again to eliminate the winter declining block rate in Ameren Missouri's next rate case, they will need to provide the Commission with more information to justify that change.

THE COMMISSION ORDERS THAT:

1. The tariff sheets filed by Union Electric Company, d/b/a Ameren Missouri on September 3, 2010, and assigned tariff number YE-2011-0116, are rejected.

2. Union Electric Company, d/b/a Ameren Missouri is authorized to file a tariff sufficient to recover revenues as determined by the Commission in this order. Ameren Missouri shall file its compliance tariff no later than July 18, 2011.

3. Governor Nixon has signed into law Missouri Senate Bill 48, which changes the procedure for parties appealing orders from the Missouri Public Service Commission. The new law took effect on July 1, 2011.

Please refer to SB 48 to become familiar with the new appellate process. An unofficial copy of the truly agreed to and finally passed SB 48 may be found at: http://www.senate.mo.gov/11info/BTS_Web/BillText.aspx? SessionType=R&BillID=4065300

Please refer to the Supreme Court Rules for further guidance. The Commission is preparing its version of Form 8, which is required by Supreme Court Rule 81.08(a).

4. This report and order shall become effective on July 23, 2011.

Steven C. Reed

Secretary

Gunn, Chm., and Jarrett, C., concur; Clayton, C., concurs with separate concurring opinion attached; Davis and Kenney, CC., concur with separate concurring opinions to follow.

Dated at Jefferson City, Missouri, on this 13th day of July, 2011.

CONCURRING OPINION OF COMMISSIONER ROBERT M. CLAYTON III

This Commissioner concurs in the Commission's Report and Order granting a rate increase to Ameren Missouri. Rate increases are never welcome by any stakeholders and involve difficult, complex decisions on the part of policy makers. This utility is the largest electric provider in the state with the greatest number of customers, which means that many fellow citizens will feel the impact of an increase in their monthly electric bills. That impact was not taken lightly by this Commissioner and it is my hope through this statement to set out the reasons why I am supporting the decision. There are two primary reasons supporting my vote in favor of the rate increase and both involve needed capital investments in the utility's infrastructure.

First, the bulk of the increase is to support the investments made at the Sioux Plant in which wet flue gas desulfurization units, or “scrubbers”, were installed, thereby improving the environmental performance of the facility. These investments, which will benefit the entire region, remove sulfur dioxide from the flue gases, as well as removing oxidized mercury, sulfur trioxide, particulate, hydrogen chloride and hydrogen fluoride. Investments, totaling approximately $574 million and involving hundreds of high-paying jobs, have been added to rate base. The investments will continue the operation of a relatively efficient and low cost facility while reducing its environmental impact. These are the types of investments which should be supported by the Commission as necessary and prudent. The Commission was unanimous in including the $31 million dollars of contested investments in rates. This environmental investment makes up the largest portion of the total rate increase.

Secondly, this Commissioner believes the Commission acted appropriately in disallowing and rejecting the additional investments made in the Taum Sauk pump-storage, hydro facility. Roughly $89 million has been completely excluded from utility rates. This Commissioner participated in the prior investigation and litigation over the utility's errors and omissions associated with the Taum Sauk disaster in December 2006. It is not an overstatement to recognize the miracle of no deaths occurring from the man-made disaster that could and should have been avoided. While the utility has taken responsibility by paying millions in penalties to government agencies and millions in damages to injured parties, it is concerning that this request for passing on these investments to rate payers is brought to this Commission. The facility is an impressive engineering marvel and its performance is an important part of the utility's generation fleet. However, we should all be mindful of its power and the impact should the facility's safety equipment fail, as in 2006. Rate payers should not be burdened with this investment which came about entirely and solely because of mistakes made by the utility.

Lastly, this Commissioner must note some dissatisfaction with other aspects of the order. While my support stems from the two issues mentioned above, the Commission could have done better in addressing other issues. For example, the Commission could have taken the opportunity to reevaluate the utility's Fuel Adjustment Clause, which inappropriately shifts too much of a burden of risk on the rate payers with an inequitable 95% to 5% division of cost. The Commission could have taken a stronger stand on Demand Side Management opportunities to empower customers to reduce their energy costs. The Commission could have taken a closer look at various costs that are being passed along to customers, which would have slightly lowered the impact of the rate increase. However, the total impact of these items is outweighed by the exclusion of Taum Sauk and support of environmental improvements at Sioux.

For the foregoing reasons, this Commissioner concurs.

Respectfully submitted,

Robert M. Clayton III

Commissioner

Dated at Jefferson City, Missouri on this 13th day of July, 2011

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Beaver County et al.
v.
Qwest Corporation fka US West Communications, Inc.
Docket No. 01-049-75

Utah Public Service Commission
June 17, 2005

Before Campbell, chairman and Boyer and Allen, commissioners.

BY THE COMMISSION:

***1** On April 29, 2005, the Commission's Hearing Officer conducted a hearing in this docket to address Qwest Corporation's (Qwest) motion for summary judgment. Participating in the proceedings were Beaver County, et al. (Counties), represented by David W. Scofield and Thomas W. Peters, of Peters Scofield Price PC; Qwest, represented by Robert C. Brown, Qwest Corporation, and Gregory B. Monson and David L. Elmont, of Stoel Rives LLP; the Division of Public Utilities (Division), represented by Michael L. Ginsberg, Utah Attorney General's Office; and the Committee of Consumer Services (Committee), represented by Paul Proctor, Utah Attorney General's Office;.

On May 12, 2005, pursuant to a March 22, 2005 Scheduling Order and the request of the parties, the Commission issued its Order Granting Motion for Summary Judgment, granting Qwest's motion for summary judgment filed on February 22, 2005. As discussed in the Scheduling Order and at the conclusion of the April 29 hearing on Qwest's motion, the Commission agreed to provide its decision in advance of its complete order, which would include findings and conclusions, to allow the parties to avoid potentially unnecessary work in connection with completion of discovery, preparation and filing of testimony and preparation for the hearing scheduled for August 9 and 10, 2005. The Commission now provides its complete order, including findings and conclusions.

I. BACKGROUND

A. Property Tax Appeals in 1988 through 1996

In each of the years 1988 through 1996, Qwest appealed the assessed valuation of its property subject to ad valorem property tax in Utah. Qwest appealed these assessments each year because it believed the assessments overstated the valuation. As a public utility, Qwest is centrally assessed by the Property Tax Division of the Utah State Tax Commission using the unitary method. The central assessment is then allocated to the Counties, the 27 counties in Utah in which Qwest has property and operations. The Counties and taxing entities within the Counties then apply their various tax rates to the assessed value allocated to them. The Counties have the right to initiate and participate in valuation appeals. Typically, they either support the assessment of the Property Tax Division or seek a higher valuation.

A hearing was held in 1994 on the appeal of the 1988 assessment, and the State Tax Commission issued a decision in November 1995, slightly reducing the assessment. Qwest appealed that decision to the Utah Tax Court. While the appeal was pending, the State Tax Commission issued a decision in *WilTel Inc. v. Beaver County, et al. v. Property Tax Division*, Appeal Nos. 95-0789 and 95-0824 (Apr. 21, 1997). Based on that decision, the Property Tax Division and Counties entered into negotiations with Qwest to resolve the 1988-1996 appeals. In March 1998, the parties entered into a stipulation in which they compromised their positions on assessed value for each year in question and established the basis for a refund based on the revised valuations. The Tax Commission approved the stipulation on April 13, 1998 and entered a supplemental order on October 2, 1998, finding that the Counties should refund $16.9 million to Qwest by December 31, 1998. The $16.9 million total was comprised of $11.5 million in principal and $5.4 million in interest.

B. Prior Litigation Regarding Refund

***2** On December 31, 1998, the Counties filed a complaint in state district court, seeking to be appointed as representatives of a class composed of all Utah ratepayers covering the period 1988 through 1996. The Counties sought class recovery of the $16.9 million stipulated property tax refund they had agreed to make to Qwest. The Counties argued that the rates charged by Qwest during the years covered by the refund were based on the property taxes originally assessed and that equity required the refund be paid to ratepayers in order to avoid a double recovery by Qwest. The Counties obtained an ex parte order allowing them to deposit their refund payments with the district court at the time they filed the complaint. In January 1999, the Counties and Qwest stipulated to a release of the funds from the district court upon Qwest posting a bond.

On December 31, 1998, the Counties also filed a petition for a declaratory order with the Commission (Docket No. 98-049-48) seeking a determination that the $16.9 million property tax refund belonged to ratepayers or, alternatively, that rates should be reduced on a going-forward basis to account for the alleged double recovery. The Counties informed the Commission that they wished the district court action to proceed first, and Qwest did not consent to the Commission matter proceeding as a declaratory order in any event.*See* Utah Code Ann. § 63-46b-21(3)(b). Based on the foregoing, the Commission took no action on the petition within 60 days, which caused it to be deemed denied.*See id.* § 63-46b-21(7). Following the 60-day period, the Division recommended to the Commission that it consider the Counties' claim in some type of proceeding. However, before the Commission could act, the Counties appealed the Commission's statutory denial of the petition to the Utah Supreme Court. They were granted a stay of the appeal pending the completion of the district court action.

Qwest moved to dismiss the district court complaint on the ground that the court lacked subject matter jurisdiction over the claim. The district court dismissed the complaint for lack of subject matter jurisdiction and allowed Qwest's bond to be released. The Counties appealed the dismissal to the Utah Supreme Court and moved to consolidate the appeal of the district court decision with the pending appeal of the Commission's statutory denial of the petition in Docket No. 98-049-48.The Supreme Court granted the Counties' motion, and the appeals were consolidated.

On September 7, 2001, the Supreme Court affirmed the decision of the district court on subject matter jurisdiction.*Beaver County v. Qwest, Inc.*, 2001 UT 81 at ££ 10-17.The Court found that even though the Counties had couched their complaint in equitable terms, the complaint really raised issues about the appropriateness of Qwest's rates during the relevant period. The Court concluded that such issues were properly within the Commission's jurisdiction. *Id.* The Court dismissed the consolidated appeal of the Commission's statutory denial of the petition for a declaratory order because the Counties failed to seek rehearing by the Commission, which is a statutory jurisdictional prerequisite to appeal.*Id.* at ££ 26-30.

C. Procedural History of This Docket

***3** The Counties commenced this docket by filing a class action complaint with the Commission on September 17, 2001. The complaint was virtually identical to the 1998 complaint the Counties had filed in district court. Qwest responded to the complaint on October 17 with a motion to dismiss on the ground that the Commission lacked jurisdiction to grant the equitable relief sought by the Counties. The Commission denied the motion without prejudice in a bench ruling on January 29, 2002. A basis of the denial stated by the Commission during the hearing on January 29 was that the Commission wanted the Counties to have an opportunity to develop facts in support of their contentions. The Commission requested that the parties meet together and discuss ways to move forward.

On June 18, 2002, a meeting was held between the Counties, Qwest, the Division and the Committee at which the parties agreed upon a schedule for initial stages of the proceeding. They agreed that discovery could commence immediately, established a schedule for the Counties to move to amend their complaint to include a claim for reparations based on exceptions to the rule against retroactive ratemaking, for Qwest and others to respond to the amended complaint, and set a technical conference on October 30, 2002, at which the parties would meet to determine whether additional discovery was required and to determine whether factual stipulations could be reached. The parties reported these matters to the Commission, and, on July 26, 2002, the Commission issued its Order Denying Motion to Dismiss Without Prejudice and Establishing a Schedule and Procedures, confirming denial of the Qwest's motion to dismiss without prejudice and adopting the schedule proposed by the parties.

The Division commenced discovery on June 28, 2002. On July 19, 2002, the Counties filed a motion to amend (with an amended complaint) and a motion to consolidate their complaint in this matter with their original petition for declaratory ruling filed on December 31, 1998 in Docket No. 98-049-48.The amended complaint added a claim for refund based on reparations and exceptions to the rule against retroactive ratemaking. The allegations in support of the latter claim were that Qwest had sought and received tax refunds which it failed to include in rate base and that it had presented differing analyses of its financial status to the State Tax Commission and the Commission. Amended Complaint (Jul. 19, 2002) at ££ 27-29. Qwest responded to the motion and amended complaint on August 9, not objecting to the motion to amend, but answering and moving to dismiss the amended complaint. Qwest filed a memorandum in opposition to the motion to consolidate on the same date. The Committee also responded to the Counties' motions on August 9, 2002. The parties thereafter filed further memoranda and motions related to the Counties' motions and Qwest's response. No party requested that the motions be scheduled for hearing.

The Counties initiated discovery on September 18, 2002. Qwest responded to discovery of the Counties, the Division and the Committee.

***4** The Commission sent a letter to the parties on September 30, 2002, asking the parties to consider at their technical conference whether agreement could be reached on the allocation of the property tax refund to each year, the allocation of the refund in each year to the Utah intrastate jurisdiction based on the allocation of property taxes in rate cases during the period, and the amount of property taxes included in setting rates in each rate case during the years in question. The letter also stated that the Commission had preliminarily determined that proceeding with the matter as a class action under the rules of civil procedure was inappropriate and unnecessarily burdensome. The Commission stated that normal Commission proceedings achieved the same benefit without the unnecessary requirements. The Commission requested that any party disagreeing with its preliminary decision submit a legal memorandum explaining the disagreement. No party did so.

At the technical conference on October 30, 2002, the Division presented a preliminary analysis regarding the allocation of the property tax refund in question to intrastate rates paid by Utah customers. Based on questions raised by Qwest and the Committee, Qwest and the Division agreed to refine this analysis and to provide it to the parties. This was done on March 5, 2003. The joint analysis showed that only approximately $5 million of the $11.5 million principal amount of property taxes refunded had been included in rates and that only approximately $2.8 million had been included in rates if the period covered by a previous refund in Docket No. 88-049-18, which was given in consideration of a general release of claims, was excluded. The Division and Qwest invited the Counties and the Committee to review and provide comments on the analysis. At a further technical conference on June 3, 2003, the Committee raised a few questions and provided comments that resulted in minor adjustments to the analysis. The Counties refused to accept the analysis, but did not provide any analysis of their own responsive to the Commission's questions except to take the position that because Qwest earned in excess of the rate of return found reasonable by the Commission in rate cases during the period from 1988-1996 in the aggregate, it recovered the entire $16.9 million property tax refund in the rates paid by Utah customers.

Qwest served data requests on the Counties on July 28, 2003. Qwest sought discovery of the factual basis for the Counties' allegations in their amended complaint. The Counties responded on September 26 and reiterated their allegations of inconsistent reporting, but rather than providing factual support for such allegations they noted that discovery was ongoing and that they would be seeking discovery from the Commission and the Utah State Tax Commission regarding Qwest's reporting. The Commission never received any discovery requests from the Counties. Nor have the Counties disputed Qwest's contention that no discovery was ever submitted to the Tax Commission.

***5** The Counties served a second set of data requests on Qwest on October 3, 2003, seeking discovery of all filings made by Qwest with the Utah State Tax Commission and this Commission during the years 1988 through 1996. Qwest responded on November 19, 2003, objecting to the requests for a number of reasons, including that they were unduly burdensome, but also agreeing to produce its files in these matters for inspection and copying at a time and place mutually agreeable to the parties. Qwest represented to the Commission that the Counties never contacted it to arrange inspection of the files, and the Counties have not challenged this representation.

Faced with an absence of significant activity in the docket, the Commission held a status conference on June 28, 2004, and issued a Scheduling Order on July 6, providing that '[o]n or before August 31st, 2004, all parties shall complete their discovery on all issues which they intend to present to the Commission for resolution in this docket.' In addition to setting a discovery deadline, the Scheduling Order required parties to file dispositive motions by September 30, 2004. On July 21, the Commission issued its Modified Scheduling Order on Qwest's Motion for Modification of Scheduling Order, limiting the effect of the discovery cutoff previously established to the Counties on the ground that Qwest and other parties should be allowed to pursue discovery once the Counties stated the factual basis for their claims.

On August 20, 2004, the Counties served a Notice of Rule 30(b)(6) Deposition of Respondent Qwest Corporation, setting the deposition for August 30. The notice identified as subject matter for the deposition information relating to property tax proceedings in all fourteen of Qwest's states from 1985 through 2000, information regarding amounts of property taxes paid or anticipated to be paid or pendency of refund proceedings reported in every regulatory proceeding in all fourteen of Qwest's states for the same period and information regarding allegations or investigations of tax, reporting, financial or accounting irregularities, misconduct or fraud, without any time or geographic limitation. Qwest responded on August 24, agreeing to produce its two employees most knowledgeable about the matters identified in the notice, on August 30 and August 31, respectively, if the depositions were limited to one day each and if questions were limited to the Utah property tax proceedings for the years 1988 through 1996 and to regulatory reports and proceedings in Utah for the years 1988 through 1997, to the accounting matters identified in the notice and to alleged irregularities with respect to reports filed with the Commission for the foregoing period of time. Qwest also agreed to allow the witnesses to respond to general questions about whether procedures and practices in Utah were also used by Qwest in other states, but stated that the witnesses would not be prepared to testify regarding specific proceedings or matters in any of the thirteen other states. The Counties informed Qwest on August 25 that they were not willing to agree to these conditions.

***6** Qwest filed a Motion for Protective Order on Notice of Rule 30(b)(6) Deposition on August 27, 2004, and the Counties filed a Motion for Modification of Scheduling Order on August 31. Following responsive filings, the Commission issued its Order Denying Motion for Modification of Scheduling Order on September 21 and the discovery period lapsed without the Counties having taken either of the last-minute depositions offered by Qwest. The Counties have not requested an opportunity for further discovery.

Pursuant to the July 6, 2004 Scheduling Order, the Counties filed a motion for partial summary judgment on September 30, 2004, seeking summary judgment that Qwest was barred from claiming that the entire $16.9 million property tax refund was not available for refund to Utah ratepayers, and Qwest filed a renewal of its prior motions to dismiss. Although the parties filed responsive memoranda on these motions, no party sought to schedule them for hearing.

On October 6, 2004, the Commission issued its Order Designating Hearing Officer and Notice of Scheduling Conference. Pursuant to that order and notice, a Scheduling Conference was held before the designated Hearing Officer, Sandy Mooy, on October 20, 2004, and a further Scheduling Order was issued on October 21, 2004. Pursuant to agreement of the parties, the Counties were to file their direct testimony by December 3, 2004, the other parties were to file rebuttal testimony by April 1, 2005, all parties were to file surrebuttal testimony by May 6, the attorneys were to hold a conference on June 2 and submit an issues matrix, and hearings were scheduled for June 7 and 8, 2005.

On December 1, 2004, the Counties filed their direct testimony, consisting of the testimony and essentially identical affidavit of Eckhardt Arthur Prawitt and the testimony of Bill Thomas Peters. On February 22, 2005, Qwest filed its motion for summary judgment based on the testimony of the Counties and an affidavit of Philip E. Grate, on behalf of Qwest, filed with the motion. The parties agreed on a schedule for responses, replies and a hearing on Qwest's motion and an adjustment of the other dates previously scheduled, which the Commission incorporated in a Scheduling Order issued March 22, 2005. On March 31, the Counties and the Committee filed responses in opposition to Qwest's motion. The Counties' response included attachments among which was a second affidavit of Mr. Prawitt. On April 22, Qwest replied. A hearing was held on the motion on April 29, 2005.

II. LEGAL STANDARD ON MOTION

Summary judgment is appropriate when documents on file ‘show that there is no genuine issue as to any material fact and that the moving party is entitled to judgment as a matter of law.‘ *See* Utah R. Civ. P. 56(c). Defending parties may move, at any time, with or without supporting affidavits for summary judgment in their favor. *See* Utah R. Civ. P. 56(b). On a motion for summary judgment, the moving party bears the burden of demonstrating that there is no genuine issue as to any material fact and that the moving party is entitled to judgment as a matter of law. However, in opposing a properly supported motion for summary judgment, the plaintiff still has the ultimate burden of proving all the elements of his or her cause of action. *See* *Thayne v. Beneficial Utah, Inc.*, 874 P.2d 120, 124 (Utah 1994). Further, ‘when a party fails to produce evidence sufficient to meet one of the elements of a claim, there can be no genuine issue as to any material fact, since a complete failure of proof concerning an essential element of the nonmoving party's case necessarily renders all other facts immaterial.' *Sanns v. Butterfield Ford*, 2004 UT App 203, £ 9, 94 P.3d 301, 304 (quotations omitted). Thus, 'once the moving party has brought forth evidence either tending to prove a lack of genuine issue of material fact or challenging the existence of one of the elements of the cause of action, the nonmoving party then bears the burden of providing some evidence, by affidavit or otherwise, in support of the essential elements of his or her claim.' *Jensen v. IHC Hospitals, Inc.*, 944 P.2d 327, 339 (Utah 1997) (quotation and bracketing omitted).

***7** It is common in Commission proceedings for the Commission to direct parties to file their testimony in written form prior to hearing. *See* Utah Admin. Code R746-100-10.G. When that is done, the practice in the hearing is to place witnesses under oath, allow them to authenticate and provide any corrections to their testimony, allow the party presenting the witness to move admission of the testimony, allow the witness to present a brief oral summary of the testimony and subject the witness to cross examination on the testimony. *Id.* Thus, upon the filing of their direct testimony, the Counties effectively presented their direct case in this matter, subject to cross examination. Accordingly, Qwest noted in its reply memorandum and in oral argument that its motion was akin to a motion under Rule 41(b) Utah R. Civ. P. to dismiss following the close of the Counties' case, in which case it would be appropriate for the Commission to actually weigh the sufficiency of the Counties' evidence rather than accord them the benefit of the higher threshold for dismissal associated with a motion for summary judgment. The Commission views such weighing of the evidence following the presentation of a direct case by the party bearing the burden of persuasion to be an efficient method to resolve some disputes without denying the complainant the opportunity to present its affirmative case but without requiring the Commission, the defendant or other parties, to bear the expense of completing a hearing; and in this case, were the Commission to engage in such weighing of the evidence it would find that the Counties clearly have not sustained their burden. However, weighing of the evidence is not necessary in order to require dismissal in this case, and by the motion being presented as one for summary judgment rather than as a motion to dismiss at the conclusion of the complainant's case, the Counties and any other interested party have been afforded an additional opportunity to present facts in support of their claim because, as noted above, parties are entitled to submit affidavits in response to a motion for summary judgment. The Counties did file such an affidavit in conjunction with their response to Qwest's motion, but it did not set forth additional material facts in dispute.

At the hearing on April 29, 2005, the Counties argued that they also intended to subpoena and call Qwest employees as witnesses in their direct case and that it would be a denial of due process if they were not allowed to do so. The Commission does have authority to subpoena witnesses, however it also has the authority to summarily dismiss a matter prior to hearing in appropriate circumstances. *See, e.g.* , Utah Code Ann. § 63-46b-1(4)(b). When those circumstances are met and summary judgment is appropriate, it is not a denial of due process to dismiss a matter prior to allowing or requiring witnesses of the opposing party to be called to the stand. When the Commission directed the Counties to file their direct testimony, it was contemplated that they would present their direct case. If the Counties were unable to fully present their direct case, on responding to Qwest's properly-supported motion for summary judgment they were required to at least provide some evidence, by affidavit or otherwise, in support of the essential elements of their claims. *Jensen*, 944 P.2d at 339. Although Utah R. Civ. P. 56(f) does further allow denial or deferral of summary judgment in the case where a party opposing summary judgment cannot, for reasons stated in an affidavit, present facts sufficient to oppose summary judgment, a party ultimately bearing the burden of persuasion cannot avoid summary judgment merely by asserting that it will obtain additional information from the movant's employees at trial.*See, e.g.* , *Celotex Corp. v. Catrett,* 477 U.S. 317, 322-24 (1986). In this case, the Counties did not present a Rule 56(f) affidavit and, in any case, had ample opportunity to develop evidence for their case prior to the date on which they filed their testimony. The Counties have made no proffer of the evidence they would hope to adduce through subpoenas and examination of Qwest witnesses at hearing, or to even identify the witnesses. As noted, the Counties were required to provide evidence that supported the essential elements of their claims in response to Qwest's motion for summary judgment. Therefore, our consideration will be limited to the evidence presented on the record.

***8** The Counties originally made their claim as one in equity that Qwest should be required to disgorge the property tax refund under a theory of unjust enrichment and constructive trust. Complaint (Sept. 21, 2001) at ££ 22-24. However, they filed an amended complaint on July 19, 2002 adding a claim for reparations based on an exception to the rule against retroactive ratemaking.

Qwest contended in its motion for summary judgment that the only valid basis for a claim for refund before the Commission was under the reparations statute, Utah Code Ann. § 54-7-20, and that such a claim could only be maintained for a refund of rates paid from 1988-1996 if an exception to the rule against retroactive ratemaking applied. In *Utah Dept. of Business Regulation v. Public Service Comm'n of Utah,* 720 P.2d 420 (Utah 1986) ('*EBA* '), the Utah Supreme Court acknowledged that the rule against retroactive ratemaking applies in Utah:

To provide utilities with some incentive to operate efficiently, they are generally not permitted to adjust their rates retroactively to compensate for unanticipated costs or unrealized revenues. [Citations omitted.] This process places both the utility and the consumers at risk that the ratemaking procedures have not accurately predicted costs and revenues. If the utility underestimates its costs or overestimates its revenues, the utility makes less money. By the same token, if a utility's revenues exceed expectations or if costs are below predictions, the utility keeps the excess. Overestimates and underestimates are then taken into account at the next general rate proceeding in an attempt to arrive at a just and reasonable future rate.

Id. at 420-21.In *MCI Telecommunications Corp. v. Public Service Comm'n,* 840 P.2d 765 (Utah 1992), the Court recognized two exceptions to the rule against retroactive ratemaking: (1) unforeseen and extraordinary increases and decreases in utility expenses that have an extraordinary effect on the utility's earnings and (2) utility misconduct that subverts the integrity of ratemaking proceedings.*Id.* at 771-72, 775.

In Qwest's reply to the responses of the Counties and the Committee to its motion, it noted that the Counties and the Committee did not maintain that the motion should be defeated based on the Counties' equitable claims. Rather, the Counties argued that summary judgment should be denied because there were disputes of material fact on the issue of exceptions to the rule against retroactive ratemaking. The Committee did not argue that there were disputes of fact or that there was evidence that one of the previously recognized exceptions to the rule against retroactive ratemaking was present, but rather argued that the Commission should fashion a remedy to deal with the refund in light of the legislative change in regulation of Qwest that occurred in 1995.

Based on the foregoing, we must decide two issues in connection with Qwest's motion: (1) whether on the undisputed material facts, the property tax refund is potentially an unforeseen and extraordinary event or Qwest potentially engaged in utility misconduct in a manner that subverted the integrity of the ratemaking process with respect to property taxes during 1988-1996, such that an exception to the rule against retroactive ratemaking might apply, and (2) whether we have authority to fashion some other remedy given the change in the manner of regulation of Qwest.

III. TESTIMONY OF COUNTIES

A. Counties' Testimony.

***9** The Counties' testimony and the second affidavit of Mr. Prawitt provided the following evidence:

Mr. Prawitt's testimony describes Qwest's accounting of the refund and notes that the crediting of the interest portion of the refund to non-operating income
results in a proportional increase in net income, which is available for distribution to shareholders. In addition, this credit appears, in accounting parlance, ‘below the line,‘ meaning that it is not an operational item that goes into rates of return for regulatory purposes. It therefore avoids the regulatory books and goes straight to the shareholders.

Direct Testimony of Eckhardt Arthur Prawitt (Prawitt) at lines 134-40. He also testified that from 1988 to 1996, Qwest over-earned, in the aggregate by 3.86% in its return on rate base and 12.51% in its return on equity and that, accordingly, in the aggregate it recovered all of its expenses including the property taxes it paid by virtue of the rates the Commission allowed Qwest to charge.*Id.* at lines 145-51.

With regard to the unforeseen and extraordinary exception to the rule against retroactive ratemaking, Mr. Prawitt testified:
I have specifically reviewed Federal Communications Commission regulation 47 C.F.R. § 32.7600(a), concerning the accounting definition for regulatory purposes of ‘extraordinary event.‘ I have also specifically reviewed APB Opinion Nos. 9 and 30 which pertain to ‘extraordinary events.‘ Based on my experience, education, skill, training and applicable generally accepted accounting standards, its is my opinion, from an accounting standpoint, that the $16.9 million property tax refund, regardless of how Qwest booked it, such a decrease in property tax expense qualifies as an ‘unforeseeable and extraordinary event.‘ My opinion in this regard is based on the fact that the property tax refund qualifies as both an unforeseeable and extraordinary decrease in Qwest's property tax expense.

Id. at lines 154-63.

With regard to the utility misconduct exception to the rule against retroactive ratemaking, Mr. Prawitt's testimony identifies what he refers to as ‘red flags‘ with respect to ‘financial reporting issues.‘ *Id.* at lines 173, 192. The ‘red flags‘ are (1) the accounting of the refund by Qwest under the Uniform System of Accounts (USOA), which leads to an increase in net income and ‘to funnel millions of dollars to shareholder return, almost one third (1/3) of which is 'below the line,'‘ (2) the fact that Qwest has appealed its property tax assessment in Utah every year, and (3) unspecified conclusions drawn from his review of ‘the proceedings in …Docket No. 88-049-18‘ and unspecified ‘matters of public record as to governmental investigations of financial fraud by former [Qwest] officers.‘*Id.* at lines 167-91. Based on these ‘red flags,‘ Mr. Prawitt draws the conclusion: ‘It is therefore my opinion that the financial reporting issues that I identify as red flags in this property tax refund scenario are, to a reasonable certainty, the result of utility misconduct.‘*Id.* at lines 191-93.

***10** Mr. Prawitt's second affidavit contained the following, which is essentially duplicative of his testimony:

2. I attended a Technical conference in the above-captioned matter on October 30, 2002. Copies of pages 1 and 4 of the DPU handout I received at that Technical Conference are attached hereto as Exhibit A.

3. As noted in the DPU Handout, based on a review

of Qwest's earnings, '[i]n the aggregate for years [1988] though 1996, Qwest actual earnings exceeded its authorized [earnings] by approximately 3.73% to 3.86% on rate base… .'

4. Given the fact that Qwest exceeded it authorized earnings return by approximately 3.73% to 3.88%, it is my opinion and conclusion that the $16.9 million refund to Qwest should be returned to Qwest's ratepayers, rather than inappropriately inuring to the benefit of Qwest's shareholders.

Affidavit of Eckhardt A. Prawitt (Mar. 31, 2005) at ££ 2-4.

Mr. Peters' testimony provides a partial history of this matter relating to the Counties' deposit of the property tax refund in the district court and the parties' stipulation that the funds could be released upon the posting of a bond by Qwest. Direct Testimony of Bill Thomas Peters (Dec. 1, 2004) (Peters) at lines 30-62. In the course of providing this history, Mr. Peters provides his recollection of a telephone conversation that he states he had during the first week of January 1999 with counsel for Qwest. Mr. Peters testifies that counsel for Qwest told him that Qwest was displeased with the fact that the property tax refund had been deposited in court because the year-end bonuses of Qwest officers were largely dependent upon the refund being paid into the Company by the end of 1998.*Id.* at lines 36-55. Mr. Peters does not attempt to draw any conclusion from this statement or to state how it relates to the Counties' claim. We note that Qwest disputes the substance of the conversation, but accepts it for purposes of the motion.

B. Competency and Admissibility of Counties' Testimony

Qwest raised questions in its motion regarding the competency and admissibility of the testimony filed by the Counties. With respect to the testimony of Mr. Prawitt, Qwest contended that Mr. Prawitt's education and experience did not qualify him to offer opinions on accounting issues, and particularly regulatory accounting and ratemaking issues, or on the ultimate issues to be decided by the Commission with regard to exceptions to the rule against retroactive ratemaking. In support of its position, Qwest cited *Patey v. Lainhart*, 1999 UT 31, £15, 977 P.2d 1193, 1196 ('The critical factor in determining the competency of an expert is whether that expert has knowledge that can assist the trier of fact in resolving the issues before it. ') (quotation omitted); *Kent v. Pioneer Valley Hosp.*, 930 P.2d 904, 906-07 (Utah Ct. App. 1997) ('By definition, an expert is one who possesses a significant depth and breadth of knowledge on a given subject… . [O]ne cannot become an expert in another specialty merely by a review of the documents in the particular case.') (quotation omitted); *Anton v. Thomas*, 806 P.2d 744, 746 (Utah Ct. App. 1991) (disqualification appropriate where no foundation had been laid regarding doctor's qualifications to testify).

***11** Qwest argued that expert witnesses are not allowed to opine on matters of law. In support of this position Qwest cited *State v. Larsen*, 828 P.2d 487, 493 (Utah Ct. App. 1992) ('Despite the appropriateness of expert testimony on an ultimate issue, Utah R. Evid. 704 was not intended to allow experts to give legal conclusions.'); *Steffensen v. Smith's Management Corp.*, 862 P.2d 1342, 1347-48 (Utah 1993) ('Even though experts can testify as to ultimate issues, their testimony must still assist the trier of fact under rule 702… . [A]n expert generally cannot give an opinion as to whether an individual was negligent because such an opinion would require a legal conclusion.') (quotation and citations omitted). Qwest argued that the applicability of an exception to the rule against retroactive ratemaking is a question of law.*MCI*, 840 P.2d at 770.

Finally, Qwest maintained that the real issue with regard to Mr. Prawitt's testimony was not necessarily his competency, but the fact that he did not offer facts in support of his ultimate conclusions. In support of this position, Qwest cited *Smith v. Four Corners Mental Health Center, Inc.*, 2003 UT 23, £

50, 70 P.3d 904, 917 ('An affidavit that merely reflects the affiant's unsubstantiated opinions and conclusions is insufficient to create an issue of fact.') (quotation omitted). Qwest argued that expert opinion must be grounded on a sufficient factual basis for a qualified expert to reasonably draw the conclusion offered to the trier of fact and that Mr. Prawitt's testimony fails to satisfy this standard. Qwest argued that his testimony fails to set forth any facts that would lead an expert on regulatory accounting or ratemaking to conclude that an exception to the rule against retroactive ratemaking applies (even assuming such a conclusion to otherwise be an appropriate subject of expert testimony), citing Utah R. Evid. 703 (facts upon which an expert bases an opinion must be 'of a type reasonably relied upon by experts in the particular field in forming opinions or inferences upon the subject '); *Williams v. Melby*, 699 P.2d 723, 725 (Utah 1985) ('An [expert] affidavit which merely reflects the affiant's unsubstantiated conclusions and which fails to state evidentiary facts is insufficient to create an issue of fact. ') (citation omitted).

With respect to the testimony of Mr. Peters, Qwest noted that Mr. Peters was legal counsel to the Counties in this matter and that his testimony ought to be excluded on that basis. Qwest cited *Watkiss and Campbell v. Foa and Son*, 808 P.2d 1061, 1066 (Utah 1991) ('We deem it generally inadvisable for members of the bar to testify in litigation where they personally represent a party. The need for the testimony of counsel must be compelling and must be necessary … as set forth in [Utah Rules of Professional Conduct] 3.7 above.').

The Counties submitted lengthy argument on the competency of Mr. Prawitt's testimony in its response and at hearing, arguing that at most Qwest's arguments went to the weight to be given to the testimony and not to its admissibility. In support of their argument, the Counties cited cases such as *State v. Kelley*, 2000 UT 41, 1 P.3d 546;*Patey v. Lainhart*, 1999 UT 31, 977 P.2d 1193;*Boice v. Marble*, 1999 UT 71, 982 P.3d 565;*Randle v. Allen*, 862 P.2d 1329 (Utah 1993); *State v. Clayton*, 646 P.2d 723 (Utah 1982).

***12** The Counties did not respond to Qwest's argument on the testimony of Mr. Peters.

In response to questions from the Hearing Officer, the Counties made concessions during oral argument that clarified the testimony of Mr. Prawitt. In response to Qwest's argument that Mr. Prawitt did not actually ever say that Qwest had accounted for the property tax refund impropriety, the Hearing Officer asked the Counties whether it was their position that Qwest had improperly accounted for the refund. The Counties conceded that they did not claim that Qwest had improperly accounted for the refund, but only that Qwest's manner of accounting for the refund allowed the refund to be available for distribution to shareholders. Tr. (Apr. 29, 2005) at 73. Qwest argued that there was no improperly with respect to property taxes' treatment in setting rates from 1988 to 1996, and that this was not a disputed fact. In response to a question from the Hearing Officer, the Counties conceded, again, that they agreed with the Committee that there was no basis for such a contention.*Id.* at 78.

These concessions, together with the fact that Mr. Prawitt has offered no facts that would support a conclusion that either of the exceptions to the rule against retroactive ratemaking apply in this case, makes it unnecessary for us to determine whether Mr. Prawitt's testimony is competent or qualified. Were we required to make such a determination, we would likely conclude that Mr. Prawitt is not qualified to offer opinions on appropriate regulatory accounting or ratemaking because he has no education or experience that would provide a basis for such opinion or that would likely be helpful to the Commission as a trier of fact in determining whether an exception to the rule against retroactive ratemaking applies in this case. Mr. Prawitt's testimony indicates that he took business and accounting courses in college and that he has extensive experience in tax auditing and appraising. However, he has no experience in public accounting or in utility regulation or ratemaking. Even if we assume Mr. Prawitt is qualified to offer opinions on regulatory accounting and ratemaking issues, his testimony provides no facts in support of his conclusions that the property tax refund was unforeseen or extraordinary in its impact on Qwest's earnings or that Qwest engaged in utility misconduct that subverted the integrity of the ratemaking process. We will discuss this issue further below.

With regard to Mr. Prawitt's opinion that because Qwest over-earned in the aggregate from 1988 through 1996, it must have recovered the entire $16.9 million property tax refund in rates, we note that Mr. Prawitt's opinion is not based on any supporting facts. On the other hand, the joint analysis of the Division and Qwest, which the Committee reviewed, provides detailed factual analysis of this issue based on public records. Mr. Prawitt has not pointed to any flaw in the analysis. As our September 30, 2002 letter indicated, many of Qwest's expenses, including its property taxes, are allocated between the intrastate and interstate jurisdictions. In setting Qwest's rates, only the intrastate portion of its expenses are considered. Therefore, even if Qwest over-earned in aggregate, which we assume it did for purposes of deciding Qwest's motion, that would only indicate that it recovered the intrastate portion of its property taxes in the rates paid by its customers. That amount is a matter of public record in the rate case proceedings. In considering Qwest's motion, we are not required to accept opinion which we know, based on our own experience and expertise and based on public record of which we may take administrative notice, is not accurate. In any event, the amount of the property taxes that are subject to refund is only relevant if Qwest's motion is denied. Since we have granted Qwest's motion, the amount of potential refund to customers is not at issue. We do finally note with regard to the size of the potential refund, however, that we reject the Counties arguments that Qwest has waived or is estopped from raising arguments about (a) intrastate versus interstate rates and (b) the effect of the limitations period contained in Utah Code Ann. § 54-7-20. The Commission has no jurisdiction to award a refund of an interstate rate; jurisdiction is not conferred or obtained from a private party, it is delegated or granted by action of the legislative body having authority over the conferral of such jurisdiction.

IV. UNDISPUTED FACTS

***13** Based on the direct testimony filed by the Counties and the affidavit of Mr. Grate, Qwest identified undisputed facts in support of its motion. The Counties responded, arguing that many of the facts were in dispute, but they failed to provide any specific factual allegations that controverted the facts provided by Qwest. Instead, the Counties contended that the facts as stated by Qwest were inconsistent with the Counties' theory of the case, that they were compound or that they were not based on the best evidence. The Commission concludes that none of these grounds creates a dispute of fact regarding the facts as provided by Qwest.

There is, of course, a dispute between the parties whether the Commission may find an exception to the rule against retroactive ratemaking based on the undisputed facts. The Counties characterize Mr. Prawitt's opinions on the exceptions to the rule as facts that are in dispute. The Commission does not agree for two reasons. First, even if Mr. Prawitt's opinions are considered to be ‘facts,‘ they are questions of ultimate fact. As noted above, Mr. Prawitt is not entitled to opine on ultimate facts without providing the underlying facts that would be relied upon by experts in the field in arriving at those opinions. He has not done so. Second, Mr. Prawitt's opinions are really conclusions of law on the ultimate issues to be decided by the Commission. Again, as noted above, such opinion is not the proper subject of expert opinion.

Therefore, for purposes of deciding Qwest's motion, the Commission notes the following facts that are undisputed on the record in this matter. The Commission does not necessarily make findings on each of these ‘undisputed facts,‘ as the Commission's findings will be addressed separately below; and the Commission notes that some of these undisputed facts (such as number 28) are conceded by Qwest solely for purposes of the Commission's consideration of Qwest's motion. The Commission has added to fact number 24 the fact noted above from Mr. Prawitt's testimony and reiterated in his second affidavit regarding Qwest's over-earnings on an aggregate basis from 1988-1996, to the undisputed facts previously provided by Qwest. In addition, the Commission has slightly modified some of the facts as stated by Qwest to remove potentially argumentative terms or emphasis or for editorial purposes based on prior references in this order. The Commission notes that several of these facts are not material to its decision on Qwest's motion. However, they provide background and context and they are undisputed for purposes of our consideration of the motion, so they are provided in this statement of facts.

1. During the years 1988 through 1996, Qwest's customers in Utah purchased telephone services from Qwest at rates found just and reasonable in Commission orders issued prior to or following appeals in Docket Nos. 87-049-T35, 88-049-07, 90-049-06, 92-049-05 and 95-049-05.In instances where rates set in these cases were adjusted following appeals, Qwest has made a refund to customers of amounts paid in excess of rates ultimately found just and reasonable in a manner ordered by the Commission. Affidavit of Philip E. Grate (Grate) £ 8.

2. In Docket No. 88-049-18, allegations of misconduct were made against Qwest. Grate £ 9; *see also* Prawitt at lines 179-81, 183-86. The allegations related to representations made by Qwest to the Commission and Division in response to questions regarding the effect of the 1986 Tax Reform Act (TRA) on Qwest's earnings and filings and responses to data requests which may have disclosed current or anticipated earnings by Qwest in excess of the rate of return found reasonable and used by the Commission in setting Qwest's rates in Docket No. 85-049-02.The allegations had no relation to the property taxes paid, the amount of property taxes included in financial reports to the Commission, the amount considered in setting rates, or any appeal of Qwest's property tax valuation in 1988 or in any other year. Grate £ 9.

3. No evidentiary hearing was ever held on the allegations of misconduct in Docket No. 88-049-18, and the Commission never made a finding regarding them. Following extensive discovery, the parties to the docket entered into a release and settlement agreement and a conditional amendment to the release and settlement agreement in which Qwest agreed, without acknowledging any misconduct, to make a substantial refund to customers to resolve the matter. Following public notices and hearings, the Commission entered an order in Docket No. 88-049-18 on April 19, 1999, approving the release and settlement agreement as amended and releasing Qwest from all claims arising out of any alleged misconduct or earnings in excess of the rate of return found reasonable by the Commission and used in setting rates in connection with rates paid from January 1, 1986 through November 14, 1989. Paragraph 3 of the ordering paragraph in the order provided:

***14** In consideration of the refund referenced in the foregoing paragraph and the other terms and conditions of the Release and Settlement Agreement as amended by the Conditional Amendment to Release and Settlement Agreement, U.S. WEST, its officers, directors, agents, authorized representatives, parent and affiliate corporations and entities and their respective officers, directors, agents, and authorized representatives, and attorneys are hereby released and discharged from any and all claims, causes of action, liabilities, obligations, suits, losses, expenses, and costs, of whatever kind or nature, which now exist or which may hereafter accrue, whether known or unknown, because of, for, arising out of, or in any way connected with Docket No. 88-049-18 before the Commission and Case

Nos. 890251 and 890252 before the Utah Supreme Court or the subject matter of any of them, including, without limitation, all claims arising out of or related to any alleged over earnings on the part of Mountain Bell for the period January 1, 1986, through November 15, 1989, including any over earnings resulting from the TRA or any alleged misconduct on the part of Mountain Bell, including any penalties, interest, late charges, or attorney fees or costs with respect thereto.

Report and Order Approving Amended Release and Settlement Agreement, *In the Matter of and Investigation into the Reasonableness of the Rates and Charges of the Mountain States Telephone and Telegraph Company*, Docket No. 88-049-18 (Utah PSC, Apr. 19, 1999) (‘*Release Order*‘) at 20; Grate £ 10.

4. In setting the rates in each of the foregoing dockets, the Commission considered Utah property taxes accrued by Qwest during the test year used in setting rates. In each case, the amount of property taxes considered in setting rates was the intrastate portion of Qwest's accrual for property taxes Qwest owed to county treasurers for the test year. Because the intrastate portion of property taxes considered in setting rates in each case was less than the full amount of property taxes accrued by Qwest, rates were lower than they would have been by the difference between the full amount of property taxes accrued and the intrastate portion of the property taxes accrued. Grate £ 11.

5. In financial reports filed by Qwest with the Commission during the period from 1988 through 1996, Qwest reported the intrastate portion of accrued property taxes for the year. In reports filed prior to assessment by the Property Tax Division, the amount Qwest reported was based on an accrued liability for property taxes. The property tax amounts shown in reports Qwest filed after the assessment reflected the true up of the accrual to reflect the amount assessed, which was also the amount paid. In each case, the intrastate portion of the property taxes included in the reports was less than the total amount of property taxes paid in each year. A schedule of accrued property taxes and the intrastate portion of such amounts for each year from 1988 through 1996 was attached to the Grate affidavit. The schedule was prepared jointly by Qwest and the Division. It was reviewed by the Committee and adjusted based on the Committee's input. Grate £ 12.

6. Qwest appealed the valuation of its property tax assessed by the Property Tax Division of the Utah State Tax Commission in each year from 1988 through 1996. Prawitt lines 101-04; Grate £ 13.

7. The Commission and the Division were aware that Qwest was appealing its property tax valuations. For example, Carl Mower, Chief Auditor of the Division, testified before the Utah State Tax Commission in the hearing on Qwest's appeal of the 1988 property tax valuation. Grate £ 14.

8. In March 1998, Qwest, the Property Tax Division and the Counties entered into a stipulation that reduced the property tax valuations that were the subject of appeals for each year from 1988 through 1996. On April 13, 1998, the Utah State Tax Commission entered its Order of Approval, approving the stipulation. In September of 1998, Qwest, the Property Tax Division and the Counties agreed upon the principal amount of property taxes paid in each year, and the interest on such principal amount, to be refunded by the Counties to Qwest pursuant to the earlier stipulation. On October 2, 1998, the Utah State Tax Commission entered its Supplemental Order, finding that the total amount of the refund of property taxes for tax years 1988 through 1996 was the sum of $16,900,000, including principal and interest up to and including December 31, 1998. Grate £ 15; *see also* Prawitt at lines 106-10. The amounts of the principal and interest components of the refund attributable to each year and the estimated intrastate portion of the components of the refund agreed upon and approved by the Utah State Tax Commission are set forth in an attachment to Grate. Grate £ 15.

9. In Qwest's 1988 general rate case, the Commission, in considering proposed adjustments to 1988 salaries and wages, referred to the *Report to the Public Service Commission of the State of Utah by the Task Force on Annualization of Test Year Data*, dated May 14, 1986, submitted by the Division, Utah Power and Light Company, Qwest and Mountain Fuel Supply Company.*See* Report and Order, *In the Matter of the Investigation into the Reasonableness of the Rates and Charges of the Mountain States Telephone and Telegraph Company*, Docket No. 88-049-07 (Utah PSC, Oct. 18, 1989) ('*1988 Order*') at 20-24. With regard to the application of the known and measurable standard to proposed test year adjustments, the 'Recommended Annualization Policy' of May 14, 1986 included the following points that the Commission quoted with approval in the *1988 Order:*

***15** 3. The changes must be specific in that it occurs at a known moment or moments in time.

4. The effects of the change must be measurable.

… .

6. The change must have already occurred or will occur before any increase in rates occurs.

Id. at 21-22.Grate £ 16. Thereafter, the Commission adopted these same standards as a rule. Utah Admin. Code R746-407-3.

10. The Commission has discussed the known and measurable standard in other decisions.*See, e.g.*, *Re PacifiCorp*, Docket No. 97-035-01, 1999 WL 218118 (Utah P.S.C. Mar. 4, 1999) (denying utility's attempt to include an income tax contingency, stating in part: 'The record shows that possible future tax assessments [after audit] for the 1997 tax year are unknown at this time. '); *see also id.* (refusing to approve expenses for a dam removal 'since … the outcome of negotiations is unknown, removal of the dam is an uncertain event. We conclude that this is a post-test-year event. The costs of removal are merely estimates, presented by the Company, grounded in this uncertain future event… . We find that the estimates do not satisfy the known and measurable standard.'); *see also In re Little Plains Water Co.*, Docket No. 96-2178-01, 1996 WL 769262, *2 (Utah P.S.C. August 7, 1996)). Grate £ 17.

11. Until the stipulation was reached, Qwest did not know whether it would prevail in its valuation appeals and the amount of excess property tax paid for each year was not known and measurable. Because the outcome of Qwest's valuation appeals and the refund of property taxes resulting from such appeals were not known until September 1998, no test year adjustments for them would have been made in any test year from 1988 through 1996; the fact that a refund would be received was not known and the amount of any such refund was not measurable. Grate £ 18.

12. When Qwest accrued the property tax refund in September 1998, it made the following accounting entries:

a. Debited $11,479,398 to Account No. 4080.11, Other Taxes Accrued - Property Tax - Operating. Grate £ 19.

b. Credited $11,479,398 to Account No. 7240.19, Operating Other Taxes - Property Taxes - Real and Personal Property. Prawitt at lines 129-30; Grate £ 19.

c. Debited $5,420,422 to Account No. 1210.99, Interest and Dividend Receivable - Other. Grate £ 19.

d. Credited $5,420,422 to Account No. 7320.90, Non-operating Income. Prawitt at lines 134-35; Grate £ 19.

13. When Qwest received the property tax refund in 1999, it made the following accounting entries:

a. In January it debited $7,101,502.60 to Account

No. 1130.1, Cash.

b. In January it credited $7,101,502.60 To Account No. 4080.11, Other Taxes Accrued - Property Tax - Operating.

c. In February it debited $9,572,269.38 to Account No. 1130.1, Cash.

d. In February it credited $9,572,269.38 to Account No. 4080.11, Other Taxes Accrued - Property Tax - Operating.

e. In March it debited $5, 420,422 to Account No. 4080.11, Other Taxes Accrued - Property Tax - Operating.

***16** f. In March it credited $5,420,422 to Account No. 1210.99, Interest and Dividend Receivable - Other.

Grate £ 20.

14. The foregoing accounting entries were entered in accordance with Utah Administrative Code R746-340-2.D, ‘Uniform System of Accounts,‘ the rule promulgated by the Commission regarding the system of accounts to be used by telephone companies in Utah. The rule provides:

Uniform System of Accounts - The Uniform System of Accounts for Class A and Class B telephone utilities, as prescribed by the Federal Communications Commission at 47 CFR 32 is the prescribed system of accounts to record the results of Utah intrastate operations.

Grate £ 21.

15. According to 47 C.F.R. § 32.1, the Uniform System of Accounts (USOA) is a historical financial accounting system which reports the results of operational and financial events in a manner which enables both management and regulators to assess these results within a specified accounting period. USOA Account No. 7240, Operating Other Taxes, USOA Account No. 7320, Non-operating Income, and USOA Account 7600, Extraordinary Items, are Other Income Accounts under Subpart F of 47 C.F.R. Part 32.*See* 47 C.F.R. § 32.6999(b), Other Income Account Listing, a copy of which was provided as an attachment to Grate. 47 C.F.R. § 32.6999, Structure of Other Income Accounts, provides in subsection (a) as follows:

The Other Income Accounts are designed to reflect both operating and nonoperating income items including taxes, extraordinary items and other income and expense items not properly included elsewhere.

Grate £ 22.

16. 47 C.F.R. § 32.7240, Operating Other Taxes, subsection (a), provides:

This account shall be charged and Account 4080, Other Taxes - Accrued, shall be credited for all taxes, other than Federal, state and local income taxes and payroll related taxes, related to regulated operations applicable to current periods. Among the items includable in this account are property, gross receipts, franchise and capital stock taxes; this account shall also reflect subsequent adjustments to amounts previously charged.

Grate £ 23. Qwest's credit to operating tax expense results in a proportional increase in net income which is available for distribution to shareholders. Prawitt at lines 130-31.

17. USOA Account 7320.90, Non-operating Income, is a subaccount of USOA Account 7300. In pertinent part, USOA Account 7300, Nonoperating Income and Expense, provides:

(a) This account shall be used to record the results of transactions, events and circumstances affecting the company during a period and which are not operational in nature. This account shall include such items as nonoperating taxes, dividend income and interest income.

Grate £ 24. Qwest's credit to non-operating income results in a proportional increase in net income which is available for distribution to shareholders. In addition, a credit to non-operating income appears, in accounting parlance, 'below the line,' meaning that it is not an operational item that would be considered in setting rates. Prawitt at lines 135-39.

18. In MCI, the Utah Supreme Court said that for the extraordinary component of the unforeseen and extraordinary exception to the rule against retroactive ratemaking to apply the event 'must have an extraordinary effect on the utility's earnings.' 840 P.2d at 771.In *Beaver County v. Utah State Tax Comm'n*, 916 P.2d 344 (Utah 1996), the Utah Supreme Court said that the 'Counties must expect, as is obvious from this case, that initial property tax assessments, especially those of large utility systems, are subject to challenges … .' 916 P.2d at 352.Grate £ 25.

19. USOA Accounts 7240 and 7320 were the proper USOA accounts in which to credit the Utah property tax refund. The Utah property tax refund would not have been properly recorded as an extraordinary item. In pertinent part, USOA Account 7600, Extraordinary Items, provides:

***17** (a) This account is intended to segregate the effects of events or transactions that are extraordinary. Extraordinary events and transactions are distinguished by both their unusual nature and by the infrequency of their occurrence, taking into account the environment in which the company operates. This account shall also include the related income tax effect of the extraordinary items.

(b) This account shall be credited and/or charged with nontypical, noncustomary and infrequently recurring gains and/or losses which would significantly distort the current year's income computed before such extraordinary items, if reported other than as extraordinary items.

Grate £ 26. The Counties do not contend that these accounting entries were improper. Tr. (Apr. 29, 2005) at 73.

20. Taking into account the environment in which Qwest operates, a property tax refund is neither unusual nor infrequent. Qwest actively monitors its property tax assessments in all states and routinely litigates what it believes to be excessive assessments. For example, during the past four years, Qwest engaged in property tax valuation litigation in Arizona, Idaho, Iowa, Montana, Oregon, Utah, and Washington. Qwest received a refund/credit of $5.6 million for tax years 2001 through 2004 in Idaho. Qwest received a refund/credit of $3.3 million in Montana for tax years 2003 and 2004. Qwest received a refund/credit of $11.1 million in Oregon for tax years 2003 and 2004. Qwest received a refund of $1.0 million in Utah for tax year 2000. Qwest has property tax valuation litigation currently pending in four states. The amount of property tax in dispute in each state is as follows: Arizona, $55.6 million; Iowa, $6.6 million; Utah, $26.3 million; and Washington, $24.6 million. These numbers represent disputed property tax amounts and are not necessarily the amounts Qwest would receive as a result of settlements or court rulings. Grate £ 27.

21. When accrued in 1998, the Utah property tax refund was not a nontypical, noncustomary and infrequently recurring gain and did not significantly distort the current year's income computed before extraordinary items. Specifically, the refund of $11.5 million (which does not reflect the effect of income taxes) was 0.11% of the Company's operating revenues, 0.14% of the Company's pre-tax operating expenses and 0.48% of the Company's 1998 pretax operating income of $2,391 million (a figure that included the $11.5 million property tax refund). Grate £ 28.

22. The property tax refund attributable to each year from 1988 through 1996 accounted for:

a. 0.02% or less of the operating revenue of Qwest in any year and 0.01% of the operating revenue of Qwest for all nine years.

b. 0.03% or less of the operating expense of Qwest in any year and 0.02% of the operating expense of Qwest for all nine years.

c. 0.12% or less of the income from operations before taxes of Qwest in any year and 0.08% of the income from operations before taxes of Qwest for all nine years.

***18** d. 0.42% or less of the operating revenue of Qwest in Utah in any year and 0.26% of the operating revenue of Qwest in Utah for all nine years.

e. 0.57% or less of the operating expense of Qwest in Utah in any year and 0.33% of the operating expense of Qwest in Utah for all nine years.

f. 1.72% or less of the income from operations before taxes of Qwest in Utah in any year and 1.23% of the income from operations before taxes of Qwest in Utah for all nine years.

Had the refund attributable to each year been recorded in that year, it would not have significantly distorted income computed before extraordinary items. Grate £ 29.

23. Qwest properly included the refund in its financial reports filed with the Commission in the applicable periods. Grate £ 30.

24. The portion of the $11.5 million property tax refund included in rates paid by Qwest's customers during 1988 through 1996 was $4,999,910. The portion of the property tax refund included in rates paid by Qwest's customers from November 16, 1989 through December 31, 1996 was $2,858,248. Grate £ 31. In the aggregate for 1988 though 1996, Qwest's actual earnings exceeded its authorized earnings by approximately 3.73% to 3.86% on rate base. Affidavit of Eckhardt A. Prawitt (Mar. 31, 2005) at £ 3.

25. Qwest ceased being subject to cost-of-service, rate-of-return regulation upon issuance of the Commission's February 17, 1998 final order in Docket No. 97-049-08.The Property Tax Division, the Counties and Qwest stipulated to reduced property tax valuations in March 1998 and to the amount of the refund in September 1998. Qwest accrued the refund in September 1998 and received cash payment of portions of the refund in January, February and March 1999. Grate £ 32.

26. Had Qwest been subject to cost-of-service, rate-of-return regulation following the property tax settlement and refund accrual in 1998, and had a rate case been commenced with a 1998 or later test year, the 1998 property tax refund would not have been considered in setting rates. The 1998 property tax refund pertained to the years 1988 through 1996. Accordingly, it would have been removed from a 1998 or later test year by a ‘prior period adjustment.‘ Grate £ 33.

27. The Counties obtained an *ex parte* order of the Third District Court on December 31, 1998, allowing the deposit of the property tax refund in the court. Mr. Peters deposited most of the refund into the court on December 31, 1998. Direct Testimony of Bill Thomas Peters (Peters) at lines 30-35.

28. Within the first week of January 1999, Mr. Peters had a telephone conversation with either George Haley or Robert Stolebarger, who were attorneys for Qwest, who expressed Qwest's displeasure at the fact that the funds had been deposited in the court and asked whether the Counties would be willing to consider having Qwest post a bond for $16.9 million in lieu of having the funds deposited in court. The Qwest attorney told him that the year-end bonus for Qwest officers was largely dependent upon the $16.9 million they had anticipated being paid into the Company at year-end 1998, and that it would have a serious impact on those officers if the funds were not paid to Qwest. Peters at lines 36-55.

29. The property tax refund accounted for 0.48% of Qwest's pre-tax operating income in 1998. Had

there been no accrual of an $11.5 million Utah property tax refund and no accrual of the related $5.4 million of interest income in 1998, the amount of annual bonus Qwest paid to its executives for 1998 operations would have been approximately $5,700 less. The Utah portion of this decreased bonus amount would have been an amount significantly less than $1,000. Grate £ 34.

30. There are public records of governmental investigations of alleged financial reporting irregularities by former Qwest officers. Prawitt at lines 181-83, 186-188.

31. The only governmental investigations of alleged financial reporting irregularities by Qwest or its former officers from 1988 through the present relate to financial reports for calendar years after 1999. Grate £ 35.

V. DISCUSSION, FINDINGS AND CONCLUSIONS

A. Equitable Relief

***19** The authority of the Commission is limited to that which is expressly granted or clearly implied by statute, *Basin Flying Service v. Public Service Comm'n*, 531 P. 2d 1303, 1305 (Utah 1975), and 'any reasonable doubt of the existence of any power must be resolved against the exercise thereof. '*Hi-Country Estates v. Bagley & Co.*, 901 P.2d 1017, 1021 (Utah 1995) (quotation omitted). Although the Counties and the Committee are no longer urging that a refund should be based on a claim for unjust enrichment or other common-law relief, so the point may be moot, we note that, as expressed by the Utah Supreme Court, the exceptions to the rule barring retroactive ratemaking have a similar basis. 'The rule …is a sound rate-making principle, but …it does not apply where justice and equity require that adjustments be made … '*MCI, supra*, 840 P.2d, at 772.

B. Claim for Reparations

The only statutory provision allowing for a refund of rates paid pursuant to final, unappealed orders of the Commission is Utah Code Ann. § 54-7-20, the reparations statute. Subsection 1 of that statute provides:

When complaint has been made to the commission concerning any rate, fare, toll, rental or charge for any product or commodity furnished or service performed by any public utility, and the commission has found, after investigation, that the public utility has charged an amount for such product, commodity or service in excess of the schedules, rates and tariffs on file with the commission, or has charged an unjust, unreasonable or discriminatory amount against the complainant, the commission may order that the public utility make due reparation to the complainant therefor, with interest from the date of collection.

The statute provides for rate reparations when charges have been in excess of the tariff or schedules in effect or have been unjust, unreasonable, or discriminatory. There is no claim by the Counties that the rates paid were in excess of the tariffs or schedules of Qwest or were discriminatory. Therefore, the only valid basis for a claim of refund would be that the rates were unjust or unreasonable.

In *American Salt Co. v. W.S. Hatch Co.*, 748 P.2d 1060 (Utah 1987), the Utah Supreme Court concluded that reparations under section 54-7-20 for 'unjust' or 'unreasonable' charges cannot be awarded when the Commission had previously determined the charges complained of to be just and reasonable in a final rate order. This holding was consistent with holdings by other courts that also found that later facts that render the previously charged rate unjust or unreasonable should only be addressed prospectively in rate-setting, not through reparations.*See, e.g.* , *Arizona Grocery Co. v. Atchison, T. & S. F. Ry. Co.*, 284 U.S. 370, 390 (1932) ('Where the Commission has upon complaint, and after hearing, declared what is the maximum reasonable rate to be charged by a carrier, it may not at a later time, and upon the same or additional evidence as to the fact situation existing when its previous order was promulgated, by declaring its own finding as to reasonableness erroneous, subject a carrier which conformed thereto to the payment of reparation measured by what the Commission now holds it should have decided in the earlier proceeding to be a reasonable rate.‘); *Entergy Gulf States, Inc. v. Louisiana Public Service Comm'n,* 730 So.2d 890, 920-21 (La. 1999) (‘A commission-made rate furnishes the applicable law for the utility and its customers until a change is made by the Commission. Therefore, the utility is entitled to rely on a final rate order until a new rate in lieu thereof is fixed by the Commission. Consequently, the revenues collected under the lawfully imposed rates become the property of the utility and cannot rightfully be made the subject of a refund.‘); *State ex re. Boynton v. Public Service Comm'n,* 11 P.2d 999, 1006 (Kan. 1932) (‘any rate …prescribed by the commission and put into effect by the carriers may be confidently collected and retained by them as their very own, without misgiving that at some future time a further hearing of the commission may be had and more evidence taken and a different conclusion reached and those rates condemned as unreasonable and reparation certificates allowed … .‘).

***20** Under these principles, a tax refund that, after the fact, affects the calculation underlying rates previously found just and reasonable by the Commission does not bring into effect the backward-looking operation of the reparations statute.

Moreover, section 54-7-20 contains a statute of limitations that would bar recovery for the Counties even if reparations were otherwise available for rates that were unjust and unreasonable at the time they were collected. Subsection (2) of section 54-7-20, provides, in part:

All complaints concerning unjust, unreasonable or discriminatory charges shall be filed with the commission within one year …from the time such charge was made … .

Thus, for each charge made to customers, the period of time in which a complaint for reparations on the ground that the rate was unjust or unreasonable may have been filed was within one year of the relevant charge. For example, if a customer wished to file a reparations claim for a charge made on January 1, 1988, the claim had to be filed by January 1, 1989. If a customer wished to file a reparations claim for a charge made on December 31, 1996, the claim had to be filed by December 31, 1997.

It has been suggested by the Counties and the Committee in prior filings and hearings in this matter that the limitations period in section 54-7-20(2) may have been tolled until the refund was paid. To argue that the refund should trigger the statute of limitations is the same as arguing that it was the refund that rendered the rates unjust or unreasonable or that the statute of limitations was tolled pending ‘discovery‘ of the refund. But the cases cited above stand for the proposition that a later occurring event, such as the tax refund, does not warrant a finding of reparations for rates that were previously found just and reasonable. This is consistent with the language of section 54-7-20, which ties the running of the statute of limitations to the ‘time such charge was made,‘ not to some later event that supposedly rendered a previous charge unjust or unreasonable. Under the one-year limitations period of section 54-7-20, the Counties were untimely in filing a reparations claim at the end of 1998 for charges that were incurred, at the latest, in 1996. As the Commission stated in the *Olympus Order*, in a similar context where the complainant argued for a tolling of the statute of limitations:

Olympus argues that the discovery rule applies; the time limitation should begin to run only after Olympus knew or should have known that it had a possible claim. Therefore, a refund for more than two years may be ordered. Olympus' argument is at odds with the unambiguous language of Utah Code 54-7-20. We reject Olympus' position that we can extend the time period beyond that clearly stated in the statute … . A refund of a monthly charge for private line service can only be had if complaint is made within two years of the monthly billing containing the private line charge. Once two years have passed since an amount was charged, a claim for a refund of the charge is time barred.

Olympus Order at 7.

***21** The Commission also stated in the *Olympus Order*: ‘While we recognize that Olympus' complaint follows an approach cognizable in courts with broad law and equity powers, we are not a court. Our powers are those conferred by statute enacted by the legislature.‘

The Counties have also argued that Qwest is barred by prior proceedings from asserting application of the limitations period in section 54-7-20. The basis of this argument is a claim that Qwest waived this argument by not raising it in previous stages of this litigation. Qwest responded that it was not required to raise this argument before it did in responding to the Counties' complaint in this docket because it moved to dismiss the district court complaint on jurisdictional grounds and because it did not respond to the petition for a declaratory order. We note that Qwest did mention the limitations period for a reparations claim in its motion to dismiss filed in this docket in 2001 and in its answer and motion to dismiss with respect to the amended complaint filed in 2002 (the first time Qwest filed an answer to the complaint). Thus, we do not believe there is any factual basis for the Counties' argument that Qwest cannot raise the statute-of-limitations argument. We also reiterate that, whether or not Qwest has preserved the argument, the Commission is bound by the limits of Section 54-7-20. Furthermore, because Qwest has acknowledged (consistent with our understanding of the MCI case) that a refund could be ordered, despite the limitations period, if we find an exception to the rule against retroactive ratemaking, it appears that this debate is largely academic. The parties agree that we may order a refund if an exception to the rule against retroactive ratemaking applies.

1. Exception to the Rule Against Retroactive Ratemaking

The Counties testimony fails to provide any basis for the Commission to find an exception to the rule against retroactive ratemaking and order a refund. Putting the testimony in its best light, it only establishes that (1) Qwest appealed its property tax assessment in Utah in each of the years from 1988 through 1996, (2) it ultimately received a refund of a portion of the amounts paid, which was accrued in September 1998 and received in January, February and March 1999, (3) it accounted for those refunds in a way that increased net income and that one-third of that amount was recorded in a ‘below-the-line‘ account in a period after Qwest was no longer subject to cost-of-service, rate-of-return regulation, (4) Qwest wanted to use the refund to pay executive bonuses attributable to the year 1998, (5) it was involved in a docket in 1988 in which allegations of utility misconduct were made, (6) there have been unspecified governmental investigations of alleged financial fraud by former Qwest officers, and (7) on an aggregate basis, Qwest earned in excess of its authorized rate of return during the period from 1988-1996.

Most of these facts are not material to a determination of whether an exception to the rule against retroactive ratemaking is present in this case.*See, e.g.* , 10A Charles Alan Wright, *et al., Federal Practice and Procedure,* § 2725 (a fact is only material for purposes of summary judgment ‘if it tends to resolve any of the issues that have been properly raised by the parties… . [A] factual issue that is not necessary to the decision is not material within the meaning of Rule 56(c) … .‘) (citations omitted). With respect to those facts that are material, they cannot forestall summary judgment because they fall short of establishing a factual basis for finding that any exception to the rule against retroactive ratemaking may be present in this case. This is particularly so where it is undisputed that (1) Qwest accurately reported the amount of property taxes accrued attributable to the intrastate jurisdiction during each test year in each rate case during the relevant period, (2) Qwest accurately reported the intrastate portion of property taxes accrued in its financial reports to the Commission throughout the relevant period, (3) the Commission and Division were aware that Qwest was appealing its property tax assessment in each year, (4) the amount of potential refund Qwest might receive based on its appeals was not known and measurable in any of the rate cases during the relevant period, (5) the amount was not known until the parties reached agreement in 1998 (after Qwest was no longer subject to cost-of-service, rate-of-return regulation), (6) Qwest properly accounted for and reported the refund when it was received, (7) the amount of the refund whether looked at on a year-by-year basis or considered in total for the nine years amounted to at most (a) 0.12% of Qwest's overall operating income before taxes or (b) 1.72% of Qwest's Utah operating income before taxes, and (8) even if Qwest were still subject to cost-of-service, rate-of-return rate regulation when the refund was received, the refund would not have resulted in any change in rates because it was related to prior periods. Accordingly, Qwest is entitled to summary judgment as a matter of law.

***22** As discussed above, the *MCI* decision recognized two exceptions to the rule against retroactive ratemaking: (1) unforeseen and extraordinary increases and decreases in utility expenses and (2) utility misconduct. These exceptions were acknowledged in the context of the court's analysis of the potential impact of the federal Tax Reform Act (TRA) on the earnings of Qwest. The Committee has argued that the *MCI* exceptions were not intended to be exhaustive, and that there may be other times where an exception to the rule would be appropriate. While that may or may not be true, the Commission will not depart from the exceptions recognized in *MCI*.*MCI* involved the impact of a change in corporate income tax rates on the earnings of a utility. Similarly, this case involves the impact of a tax refund on the earnings of a utility. The *MCI* court's discussion is based on the change in expense levels and the impact on the earnings of the company. The Counties' claim is also based on the change in expense levels of the company (for property taxes) and the impact on the earnings of the utility. The circumstances are analogous enough that we see no basis to depart from the *MCI* standards.

The *MCI* court stated that for the extraordinary component of extraordinary-and-unforeseeable exception to apply the event ‘must have an extraordinary effect on the utility's earnings.‘840 P.2d at 771.Thus, the ‘increase or decrease [in earnings] will necessarily be outside the normal range of variance that occurs in projecting future expenses.‘ *Id.* at 771-72.

The Court also considered statements by Company representatives made in response to a Commission request for information on the anticipated impact of the TRA on earnings, as well as information provided by the Company during discovery, and determined that it was arbitrary and capricious for the Commission to have failed to hold a factual hearing on whether the Company had engaged in utility misconduct. In so doing, the court recognized an exception to the rule against retroactive ratemaking for utility misconduct, holding ‘[t]he rule against retroactive rate making was not intended to permit a utility to subvert the integrity of rate-making proceedings.‘*Id.* at 775.

a. Unforeseen and Extraordinary Exception

Mr. Prawitt's testimony concludes that the property tax refund was an unforeseeable and extraordinary event based on his review of 47 C.F.R. § 32.7600(a) and APB Opinion Nos. 9 and 30, and based on the fact that it decreased Qwest's property tax expense. Prawitt at lines 154-63. This testimony falls short of meeting the test enunciated in *MCI*.In this case, the property tax refund was neither unforeseen nor extraordinary. It was foreseeable because the Commission and Division knew that the Company was appealing its property tax assessments in each year and because the Company would not have filed appeals if it had no chance of prevailing. Thus, it was foreseeable that the Company might prevail and if it prevailed that it would obtain a refund of some portion of the property taxes previously paid. The property tax refund was not extraordinary because it did not have an extraordinary impact on earnings. The refund also was not atypical or noncustomary, as would be relevant to identifying an extraordinary accounting item, Grate £ 26.

***23** The Counties' theory with respect to utility misconduct supports the view that the refund was foreseeable. Otherwise, how could the Company ‘use property tax appeals as a mechanism …to funnel millions of dollars to shareholder return.‘ Prawitt at lines 171-72. This mechanism would only work if it was clearly foreseeable that the Company would prevail in its property tax appeals and receive a refund.

Under *MCI*, there must be a significant impact on earnings before an event becomes extraordinary. *See, e.g.* , 840 P.2d at 771.This standard applied by the Supreme Court is supported by the very section of the FCC's regulations cited by Mr. Prawitt. According to that section, the account for extraordinary items ‘shall be credited and/or charged with nontypical, noncustomary and infrequently recurring gains and/or losses which would significantly distort the current year's income computed before such extraordinary items, if reported other than as extraordinary items.‘47 C.F.R. § 32.7600(b).

As Mr. Grate's affidavit establishes, a comparison of the refund with the total operating revenues, expenses and income before income taxes over the relevant nine-year period shows that the refund constituted 0.01% of revenues, 0.02% of expenses and 0.08% of income from operations before taxes. For any given year, the refund for that year never exceeded 0.02% of operating revenues, 0.03% of operating expenses or 0.12% of income from operations before taxes. Considered on a Utah-only basis, the refund constituted 0.26% of revenues, 0.33% of expenses and 1.23% of income from operations before taxes. The undisputed facts are that, whether looked at in relation to 1998 income or on a year by year basis, the refund did not significantly distort or would not have significantly distorted income computed before extraordinary items. Grate ££ 28-29. Because we are also the trier of fact in the administrative process, we are the 'reasonable person' that is to view the evidence. We are able to conclude that reasonable minds can find that the refund was not extraordinary.

Other considerations outside those strictly relevant under *MCI* also demonstrate that the property tax refund was not extraordinary. For example, USOA Account 7600, Extraordinary Items, which is also cited by Mr. Prawitt, states, ‘Extraordinary events and transactions are distinguished by both their unusual nature and by the infrequency of their occurrence, taking into account the environment in which the company operates.‘ It also refers to extraordinary items as ‘nontypical, noncustomary and infrequently recurring gains and/or losses.‘ 47 C.F.R. § 32.7600. As noted by Mr. Grate after providing facts on the regularity of property tax appeals and refunds, ‘Taking into account the environment in which Qwest operates, a property tax refund is neither unusual nor infrequent.‘ Grate £ 27. The Division has informal criteria for making a determination in this regard. Among other things, the event must have been unusual, unique, infrequent, and not part of normal operations.

***24** The other sources cited by Mr. Prawitt also agree with these criteria.*See, e.g.*, APB Opinion No. 30 at £ 30.20 (Requiring an extraordinary event to be both unusual and infrequent. To be unusual it must have a ‘high degree of abnormality and be of a type clearly unrelated to, or only incidentally related to, the ordinary and typical activities of the entity.‘); id. at £ 30.22 (To be infrequent, it must be ‘an event or transaction of a type not reasonably expected to recur in the foreseeable future … . The past occurrence of an event or transaction for a particular entity provides evidence to assess the probability of recurrence of that type of event or transaction in the foreseeable future. By definition, extraordinary items occur infrequently. However, mere infrequency of occurrence of a particular event or transaction does not alone imply that its effects should be classified as extraordinary. '); id. at £ 30.19 ('[A]n event …should be presumed to be an ordinary and usual activity of the reporting entity, the effects of which should be included in income from operations, unless the evidence clearly supports its classification as an extraordinary item as defined in this Opinion.').

Qwest's property tax appeals, and the resulting refund, cannot be said to qualify as extraordinary under any of these additional criteria. As the Utah Supreme Court previously told the Counties in another case: 'Counties must expect, as is obvious from this case, that initial property tax assessments, especially those of large utility systems, are subject to challenges … .' *See Beaver County,* 916 P.2d at 352.It is undisputed that Qwest's filing of property tax appeals and receipt of refunds or credits is neither infrequent nor unusual. Grate £ 27. As the Division appropriately concluded earlier in this case: 'Applying [the Division's] guidelines, the Division does not believe that the Counties' Complaint satisfies the 'extraordinary' test in that Qwest's property tax appeals are not 'unusual,' 'unique,' or 'infrequent,' and may be said to be 'a part of normal operations.'' Preliminary Response of the Division of Public Utilities to the Counties' Complaint and Qwest's Motion to Dismiss (Dec. 11, 2001) at 3. No new facts have been presented by the Counties that undermine the Division's conclusion.

Finally, as noted above, the Counties do not contend that Qwest accounted for the refund improperly. Although Mr. Prawitt cited the definition of extraordinary items under the USOA, he did not testify that Qwest should have recorded the refund in the extraordinary items account. Therefore, Mr. Grate's testimony that the refund was properly booked in different accounts, and would not properly have been booked in the extraordinary items account, is uncontested.

Summary judgment is appropriate on the issue of the unforeseen and extraordinary prong of the MCI exceptions to the rule against retroactive ratemaking.*See, e.g.* , *Olympus Hills Shopping Center, Ltd. v. Smith's Food & Drug Centers, Inc.,* 889 P.2d 445, 450 (Utah Ct. App. 1995) ('A trial court may properly grant a motion for summary judgment or directed verdict … when reasonable minds could not differ on the facts to be determined from the evidence presented.') (citations omitted).

b. Utility Misconduct

***25** The Counties' evidence of utility misconduct consists of a phone conversation in which counsel for Qwest told Mr. Peters that Qwest was displeased with the fact that the funds had been deposited in court because the year-end bonuses of Qwest officers were largely dependent upon the refund being paid into the Company by the end of 1998 and Mr. Prawitt's three 'red flags:' (1) the accounting of the refund by Qwest under the USOA, which leads to an increase in net income and 'to funnel millions of dollars to shareholder return, almost one third (1/3) of which is 'below the line,'' (2) the fact that Qwest has appealed its property tax assessment in Utah every year, and (3) unspecified conclusions drawn from Mr. Prawitt's review of 'the proceedings in …Docket No. 88-049-18' and unspecified 'matters of public record as to governmental investigations of financial fraud by former [Qwest] officers. ' Prawitt at lines 167-93. With the possible exception of the allegation relating to Docket No. 88-049-18, these allegations are deficient as a matter of law.

The Court made it clear in *MCI* that the utility misconduct exception to the rule against retroactive ratemaking involves conduct that 'subvert[s] the integrity of rate-making proceedings.' 840 P.2d at 775.Thus, the misconduct cannot be based on general allegations of 'financial fraud' or improper motive. It must relate to financial fraud or misrepresentation in the context of the ratemaking process. With the possible exception of Docket No. 88-049-18, which is addressed below, this evidence is completely absent in the Counties' testimony.

Mr. Peters' testimony was apparently provided to suggest that Qwest's motive in seeking property tax refunds was to provide money to pay officers' bonuses. However, the testimony is irrelevant to any claim of utility misconduct. The rates at issue in this case were set in 1987, 1988, 1990, 1992 and 1995. The use of the refund in 1998 or 1999 had no relationship to the setting of rates at issue in those cases and does not constitute evidence of utility misconduct providing an exception to the rule against retroactive ratemaking with respect to the rates at issue in those cases.

In addition, there is nothing improper about using a tax refund or any other source of cash and income, properly accounted for, to pay management bonuses. As noted above and as will be discussed in more detail following, there is no contention that Qwest accounted for the refund improperly.

Mr. Prawitt's first red flag is the accounting of the refund. The refund was accounted for in 1998 and 1999. As previously noted, the accounting of the refund had no relationship to the setting of rates at issue in cases during 1987-95 and, even if improper, could constitute no evidence of utility misconduct providing an exception to the rule against retroactive ratemaking with respect to the rates set in those cases. In addition, Mr. Prawitt's red flag is not a red flag at all. Other than calling it a red flag, Mr. Prawitt makes no contention that it represented improper accounting for the refund in any way. On the other hand, Mr. Grate's affidavit establishes that Qwest's accounting for the refund complied with 47 C.F.R. Part 32 and was, in fact, the only accounting that could properly be made. Grate £ 26. As noted above, during oral argument the Counties conceded that they do not contend that Qwest accounted for the refund improperly. Tr. (Apr. 29, 2005) at 73.

***26** Mr. Prawitt's second red flag is that Qwest appealed its property tax assessment in Utah in every year. Again, this has nothing to do with setting rates in rate cases. Furthermore, it does not constitute any type of misconduct. Qwest is entitled by law to appeal property tax assessments that it believes are excessive. The fact that it not only appealed the assessments but was successful in obtaining a stipulated refund, representing an acknowledgement by the Property Tax Division and the Counties that there was a risk that the Tax Commission may have found that Qwest's assessments were too high, demonstrates that the appeals were taken in good faith and were appropriate.

Mr. Prawitt's third red flag relates to allegations of improper conduct in Docket No. 88-049-18 and in governmental investigations of alleged financial fraud by former Qwest officers. Allegations of misconduct in connection with setting of rates in 1987 and 1988 were made during the course of Docket No. 88-049-18.Mr. Prawitt claimed support for his opinion of utility misconduct based on a review of the proceedings in Docket No. 88-049-18, but he did not cite any facts disclosed by his review that support a finding of misconduct related to inclusion of property taxes in setting rates. The only allegations of misconduct in that docket related to responses by Qwest to the Commission and the Division regarding the effect of the TRA on earnings and filings and responses to data requests which may have disclosed over earnings. Grate £ 9. These allegations were never proven and the Commission never made a finding that any misconduct occurred. However, assuming that the allegations were true, they had nothing to do with property taxes paid, the amount of property taxes included in financial reports to the Commission, the amount of property taxes considered in setting rates, or any appeal of Qwest's property tax valuation in 1988 or in any other year.*Id.*

Further, Qwest and other parties to those proceedings, including the parties making the allegations of misconduct, entered into a release and settlement agreement and conditional amendment to release and settlement agreement to resolve almost ten years of contentious litigation. In consideration for Qwest's agreement to make a substantial refund to Utah customers, the parties agreed to release Qwest of any further claims relating in any way to allegations of misconduct or overearnings from January 1, 1986 through November 15, 1989. Following public notice, the Commission reviewed the agreement in public hearings and entered an order releasing Qwest. Thus, even if there were some basis for believing that Qwest may have made misrepresentation in 1987 or 1988 regarding property taxes, Qwest has been released from claims with respect to any such alleged misrepresentations.

The Counties contend that they are not bound by the release in Docket No. 88-049-18 because they were not parties to the docket. This contention is not valid. The Division represented the interests of all ratepayers in that docket, and the Committee represented the interests of residential, small commercial and agricultural ratepayers. In addition, other parties appeared in a representative capacity, including MCI Telecommunications Corp. and Tel-America of Salt Lake City, Inc. In fact, it was the latter two parties that initiated the proceeding on behalf of all ratepayers. The Counties could have intervened in the proceeding had they been interested.

***27** As noted above, Commission proceedings with respect to ratemaking and claims related to ratemaking inherently involve the interests of all ratepayers, and the Commission considers the interests of all ratepayers in deciding such cases. An important consideration for Qwest in making a substantial refund in that docket was the agreement of the parties that it would be released from all claims that could result in additional refunds based on over-earnings or claims of utility misconduct during the period at issue in that case. The Commission carefully considered these issues in requiring Qwest to publish notice of the proposed settlement and in holding public hearings on it. In fact, as a result of the appearance by entities not previously involved in the docket, the Commission required Qwest and the parties to modify the settlement before it could be approved in the public interest.

Just as the Commission can grant ratepayers benefits across customer classes without requiring a class to be certified under Utah R. Civ. P. 23, the Commission need not make a utility litigate claims with every customer before the Commission declares a release to be in the public interest. All of Qwest's customers received the benefit of the multimillion dollar *MCI* refund, after being given ample opportunity to participate in the proceeding. The Commission cannot in fairness now deprive Qwest of the benefit of the bargain it struck in entering into that settlement.

Mr. Prawitt provided no factual support for the proposition that the governmental investigations of alleged financial fraud by former Qwest officers involved conduct related to any rate case in Utah or anywhere else. Although Mr. Prawitt did not provide any factual context or basis for his statement, he was apparently referring to the governmental investigations of Qwest and certain of its officers relating to accounting used in post-1999 financial statements, which have been widely publicized. Grate at £ 35. Financial or accounting errors in post-1999 financial statements would have had nothing to do with the integrity of rate cases in Utah from 1987 through 1995. There is no nexus between alleged financial fraud after 1999 and ratemaking in 1987 through 1995.

Utility misconduct in the context raised by the Counties is a serious charge. It amounts to a claim that Qwest committed fraud on the Commission by making false statements or intentionally withholding material information about its property taxes. As such, the Counties were required to allege the fraud with particularity and prove it by clear and convincing evidence.*See e.g.* , *Williams v. State Farm Ins. Co.,* 656 P.2d 966, 972 (Utah 1982) (‘The purpose of [the Rule 9(b)] requirement dictates that it reach all circumstances where the pleader alleges the kind of misrepresentations, omissions, or other deceptions covered by the term 'fraud' in its broadest dimension. Consequently, if the pleading had merely alleged that the insured had given 'fraudulent' or 'deceptive' or 'misrepresenting' answers, it would have been insufficient. '); *Secor v. Knight,* 716 P.2d 790, 794 (Utah 1986) ('[I]n order to prevail on a claim of fraud, all the elements of fraud must be established by clear and convincing evidence.') (citing *Cheever v. Schramm,* 577 P.2d 951, 954 (Utah 1978)). On a motion for summary judgment it is appropriate to consider the ultimate burden of persuasion that would have to be borne at trial when considering whether there is any genuine issue of material fact.*See, e.g.* , *Andalex Resources, Inc. v. Myers,* 871 P.2d 1041, 1046 (Utah Ct. App. 1994) ('In granting a motion for summary judgment, a trial judge must consider each element of the claim under the appropriate standard of proof.') (citations omitted). Here, not only did the Counties fail to bring evidence of specific facts that could establish utility misconduct (whether by clear and convincing evidence or merely by a preponderance of the evidence), after years of opportunity to conduct discovery and present their case, they failed to even identify any specific allegation of misconduct related to rate setting. And, as noted above, they conceded at the oral argument on Qwest's motion that other than their theory of the case, they had no facts demonstrating that Qwest had done anything improper in the rate-setting process from 1988-1996. Therefore, it is undisputed that Qwest did not misrepresent or withhold facts related to its property taxes or property tax appeals and there is no basis for a Commission finding that utility misconduct has occurred.

***28** Based on the fact that the Counties have provided no facts which could support a finding of utility misconduct, all that is left is the Counties' theory that Qwest engaged in utility misconduct by filing property tax appeals every year to convert a portion of its property tax expense into net income that would not be considered in setting rates. Prawitt at lines 167-76, 188-91. For this theory to be correct, at least three things must be assumed.

First, it would have to be assumed that the Property Tax Division, with the support of the Counties, purposely overvalues Qwest's property so that Qwest is assured of a refund each and every year. Otherwise, Qwest is unable to successfully engage in this 'misconduct.' We reject this assumption. Rather, it must be assumed that the Property Tax Division attempts to assess Qwest accurately. We note that the Counties' conduct is inconsistent with this theory because they support the Property Tax Division's valuations or seek an even higher valuation and always oppose Qwest's valuation appeals. Thus, under the Counties' theory, either the Property Tax Division and the Counties are knowingly seeking excessive valuations to assist Qwest in its scheme, or they are unwitting accomplices.

Second, it would have to be assumed that there is something improper about Qwest appealing excessive valuations. If the Property Tax Division overvalues Qwest's property, Qwest is legally entitled to appeal and seek a reduction in valuation. In fact, if Qwest failed to challenge excessive valuations, it is possible that a party in a Qwest rate case (if Qwest were still subject to cost-of-service regulation) would challenge Qwest's property tax expense as being excessive because it is based on excessive valuations that Qwest has not appealed.

Third, it would have to be assumed that Qwest could either pay some lesser amount of property taxes pending its appeals or that it should propose an adjustment to its actual property tax expense in rate cases in anticipation of receiving a refund at some time in the future. The first assumption is not valid. Qwest is required to pay the amount assessed pending appeal. The second assumption ignores the Commission's consistent position regarding known and measurable adjustments to test-year expenses which will be discussed in more detail below.

The remaining question is whether knowing that it was appealing its property taxes, Qwest engaged in utility misconduct because it included the property taxes accrued in the test years in its regulatory reports and in its rate case filings rather than an adjusted amount based on a hoped-for refund. Before addressing this question, we note again that no party claims that Qwest engaged in misconduct in the rate setting process. Rather, the Counties suggest that the combination of property tax appeals and refunds which are properly accounted for below-the line is some sort of scheme that together results in misconduct. The Counties did not articulate how this could be the case. However, Qwest argued that this must assume that Qwest engaged in misconduct by failing to make adjustments in its test-year expenses to account for the possibility of a refund. Qwest argued that such an adjustment would be inconsistent with the Commission's rules and standards for known and measurable adjustments and would have been improper.

***29** Pursuant to the known and measurable standard, during the years at issue in this docket, the Commission typically 'require[d] an historical test year with adjustments for only known and measurable changes.' *Re Little Plains Water Company,* Docket No. 96-2178-01, 1996 WL 769262 (Utah P.S.C. Aug. 7, 1996); *see also, e.g., Public Service Co. of Colorado v. Public Utilities Comm'n,* 26 P.3d 1198, 1206 (Colo. 2001) ('adjustments made outside the test year may occur only when costs are known and measurable'); *Western Resources, Inc. v. State Corp. Comm'n*, 42 P.3d 12, 168 (Kan. Ct. App. 2002) (Kansas commission 'has discretion to include in rate calculations any costs and revenues not part of the test year if the changes are known and measurable. '). Thus, Qwest could no more request that rates be based on speculative future lower tax assessments (decreasing its revenue requirement) than it could request that rates be based on speculative future higher assessments (increasing its revenue requirement).

In Qwest's 1988 general rate case, the Commission, in considering proposed adjustments to salaries and wages, addressed the standards for known and measurable adjustments that could be considered in setting rates. Among those standards, the Commission required that:

3. The change must be specific in that it occurs at a known moment or moments in time.

4. The effects of the change must be measurable.

… .

6. The change must have already occurred or will occur before any increase in rates occurs.

See 1988 Order at 21-22. These standards were subsequently adopted in Rule R746-407-3 and remain in effect today.

Possible refunds from property tax appeals do not fit any of these standards. They did not occur at moments in time that were known during the relevant rate cases, the amount of the refunds was not measurable during the rate cases and the refunds had not already occurred and did not occur before the rates under consideration became effective.

The Commission has consistently denied utility requests that they be allowed to include increases in income taxes following audits in rates because, even though the increases occur regularly, they are not known and measurable.*See, e.g., Re* PacifiCorp, Docket No. 97-035-01, 1999 WL 218118 (Utah P.S.C. Mar. 4, 1999), where the Commission addressed this issue and stated:

The Division argues for the removal of this adjustment on grounds that the results of future tax audits cannot be known and cannot be measured … [A] Report [from an outside accounting firm retained by the Division] holds that the inclusion of tax contingencies in cost of service is not common and is not appropriate, and specifically recommends excluding income tax contingency accruals from PacifiCorp's cost of service. The Division testifies that tax contingency accruals have been excluded in recent rate cases and cost-of-service studies for both Mountain Fuel and US West. This recommendation is supported by the Committee.

***30** The record shows that possible future tax assessments [after audit] for the 1997 tax year are unknown at this time.

See also id. (refusing to approve depreciation expenses for a dam removal because ‘since no agreement to remove the dam had been signed during the test year, and the outcome of negotiations is unknown, removal of the dam is an uncertain event. We conclude that this is a post-test-year event. The costs of removal are merely estimates, presented by the Company, grounded in this uncertain future event. No economic examination of the estimates has been undertaken by all parties in this proceeding. We find that the estimates do not satisfy the known and measurable standard.‘).

Indeed, even being ‘known and measurable‘ would not have assured that a post-test-year expense would have been considered during the 1988-1996 time frame. As the Commission held in the same order quoted immediately above:

[A] post-test-year adjustment presents a special and serious case of matching and information insufficiency. It is a single-item adjustment, proposed because it is ‘known and measurable.‘ Since, by definition, it is outside the test year, it cannot be analyzed in a test-year context of matched revenues, expenses, and investments. Hence, it is akin to a single-item rate case. All the arguments against conducting single-item rate cases argue against consideration of post-test-year adjustments. The fact is, events do not occur in isolation. The utility is a complex web of economic relationships, each of which changes as the result of external and internal forces and events. This is the proper context for considering any proposed adjustment.

Id.

Based on these precedents, any attempt to have included an adjustment to Qwest's property tax expense in any of its rate cases based on the potential future outcome of an appeal of the property tax assessments and the possibility of a future refund likely would have been rejected by the Commission as a prohibited out-of-period adjustment. In sum, there is neither factual support for a potential finding of unforeseen and extraordinary circumstances nor factual support for a finding of utility misconduct in this case. Although the Division took no position on Qwest's motion for summary judgment, at the hearing it did confirm that it continues to believe as it did earlier in this case that, even following discovery, there is no applicable exception to the rule against retroactive ratemaking in this case. The Commission agrees.

C. Claim for Future Rate Adjustment

In the alternative to a refund to be awarded as rate reparations, the Counties sought ‘appropriate adjustments in future rates‘ to account for the $16.9 million property tax refund. Amended Complaint £ 31. Based on the argument on Qwest's motion, it does not appear that any party continues to urge this result. Such a course of action would be problematic in any event.

From February 17, 1998 to May 2, 2005, prices for Qwest's public telecommunications services were determined either by application of a price index or indices to tariffed services, see Utah Code Ann. § 54-8b-2.4 (2004), or through Qwest's exercise of pricing flexibility for services for which competitive alternatives exist.*See id.* at § 54-8b-2.3 (2004). Since May 2, 2005, all of Qwest's prices are subject to pricing flexibility, with a cap on basic residential rates until further competition develops in that market.*See* id. at § 54-8b-2.3(2) (2005). Any rate-setting by the Commission is confined to the conditions and requirements of those two methods of setting prices. The legislature has established the ratemaking process to be followed. The Commission must give effect to legislative intent. Since the Commission has concluded that there is no basis for an exception, whether the remedial tool should be a refund or a rate change is academic in any case

D. Fashion Another Remedy

***31** The Committee does not attempt to dispute any of the foregoing analysis. In fact, the Committee acknowledges that there is no evidence that the property tax refund was unforeseen or extraordinary or that Qwest engaged in utility misconduct under the *MCI* analysis. Instead, the Committee argues that because Qwest was removed by legislation from cost-of-service regulation in 1997, the Commission should fashion a remedy because ratepayers will not benefit from reduced property tax assessment in the future through lower rates - that this change in regulation created a new type of extraordinary circumstance that would qualify for an additional exception to the rule against retroactive ratemaking. The Counties likewise argue that the Commission has authority to fashion some remedy. The Committee and the Counties have cited section 54-4-1 and the *MCI* decision as authority for fashioning such a remedy. Section 54-4-1 provides:

The Commission is hereby vested with power and jurisdiction to supervise and regulate every public utility in this state, and to supervise all of the business of every such public utility in this state, and to do all things, whether herein specifically designated or in addition thereto, which are necessary or convenient in the exercise of such power and jurisdiction … .

On its face, it appears that this statute might provide a basis for the authority to fashion a remedy. However, Qwest responds that the Commission does not have authority to fashion a remedy other than the remedies expressed or clearly implied by statute.*See Basin Flying Service; Hi-Country Estates, supra*.Because of Utah case law holding that Section 54-1-1 is not as expansive as its literal language would lead one to believe and the lack of evidence to explore a possible exception from the rule against retroactive ratemaking, the Commission should not embark on a course to create a remedial tool beyond what has already been recognized.

This conclusion is reached in consideration of the statutory changes that have been made by the Utah legislature with respect to Commission regulation of telecommunications corporations in this state. When Utah departed from traditional cost-based-rate-of-return regulation to a price indexed regime, the legislature indicated that Qwest would ‘not be regulated on the basis of rate of return or any similar method of regulation that is based on the earnings [of Qwest] … .‘ Section 54-8b-2.4(2) (2004). The legislature's most recent enactments, from the 2005 legislative session, evidence with even greater clarity the state's further distancing from reference to or consideration of Qwest's actual costs or expenses incurred in providing services and the earnings which it may obtain. Effective May 2, 2005, Qwest is authorized to set it own prices without any modification or consideration by the Commission. Section 54-8b-2.3 (2005). The state has departed from even the indirect price-indexing rate setting approach. Since the rule against retroactive ratemaking and its exceptions are based on ratemaking principles, *see Stewart v. Utah Public Service Commission*, 885 P.2dd 759, 777 (Utah 1994), it is not appropriate, at this time, for the Commission to extend remedies beyond *MCI's* parameters and the rate setting authority delegated by the legislature.

***32** The Committee cited *In re Central Hudson Gas & Elec. Corp.*, 2004 WL 3098825 (N.Y.P.S.C. Dec. 20, 2004), in support of its view that the Commission should fashion a remedy. In response, Qwest argued that the case was inapposite because it was based on a New York statute not present in Utah. Specifically, the New York statute explicitly authorizes the commission ‘[w]henver any public utility company …receives any refund of amounts charged and collected from it by any source …to determine whether or not such refund should be passed on, in whole or in part, to the consumers of such public utility company… . ‘N.Y.P.S.L. § 113 (2) (quoted in *Central Hudson* at 2, n.2). We find that the specific New York statute provided the authority for the New York PSC to divide a refund between ratepayers and the public utility. No such statute exists in Utah. The Utah legislature does know how to enact such provisions. In its 1995 enactments, the Utah legislature did provide for rates to be impacted by changes in tax rates; in addition to a variety of other specified matters that could be factored in setting rates. Section 54-8b-2.4(5)(b) (2004). In 2005, the legislature did not include any provisions to hold place for rate impacts for any pending regulatory matters or future developments in Commission regulation of Qwest.

VI. CONCLUSION

The Commission concludes that the it can not provide relief through statutory rate reparations. That relief lapses for rates or charges paid in periods more than one year prior to the date a request for refund is made. No relief is available through an exception to the rule against retroactive ratemaking. Despite having many years to conduct discovery and make their case, the Commission concludes that the Counties have failed to introduce sufficient evidence (in opposition to Qwest's Motion for Summary Judgment) that could support a Commission finding that an exception to the rule against retroactive ratemaking could be made in this case. The Counties have failed to introduce evidence necessary to support an essential element of their cause of action and summary judgment is appropriate.

The Commission denied Qwest's original motion to dismiss without prejudice in January of 2002 in order to allow the Counties and any other interested party an opportunity to develop and present facts in support of their claims. Despite having over two and one-half years to develop such evidence, the Counties have failed. In addition, the Division and Committee, who conducted their own discovery, have concluded that there is no basis for any claim that the property tax refund was unforeseen and extraordinary under *MCI* or that Qwest accounted for the property tax refund improperly or engaged in utility misconduct in connection with the setting of rates. Although we have not had an evidentiary hearing on the Counties' claims, there is plainly no reason for such a hearing. The Counties have filed their direct case and opposing affidavits, Qwest has filed an affidavit providing additional evidence and there is no genuine issue as to any material fact. The law does not provide for the relief sought by the Counties.

***33** Based upon the foregoing undisputed facts and the conclusions of law, the Commission makes the following order.

ORDER

IT IS HEREBY ORDERED that:

1. Qwest's motion for summary judgment is granted and the Amended Complaint of the Counties is dismissed with prejudice.

2. This Order consititutes the Commission's final agency action. Pursuant to Utah Code Ann. §§ 63-46b-12 and 54-7-15, agency review or rehearing of this order may be obtained by filing a request for review or rehearing with the Commission within 30 days after the issuance of the order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the Commission fails to grant a request for review or rehearing within 20 days after the filing of a request for review or rehearing, it is deemed denied. Judicial review of the Commission's final agency action may be obtained by filing a Petition for Review with the Utah Supreme Court within 30 days after final agency action. Any Petition for Review must comply with the requirements of Utah Code 63-46b-14, 63-46b-16 and the Utah Rules of Appellate Procedure.

DATED at Salt Lake City, Utah, this 17th day of June, 2005.

Approved and Confirmed this 17th day of June, 2005, as the Report and Order of the Public Service Commission of Utah.

END OF DOCUMENT

Re Commonwealth Edison Company
05-0597

Illinois Commerce Commission
July 26, 2006

ORDER authorizing an electric utility to increase its delivery service rates by $8.331 million, or 0.50%, reflecting a 10.045% rate of return on common equity and a return on net original cost rate base of 8.01%.

In determining capital structure for rate-making purposes, the commission excludes a net $2.634 billion goodwill asset generated in part by the transfer of nuclear power plants by the utility to an unregulated generating affiliate. Commission adopts a hypothetical capital structure of 42.68% equity and 57.14% debt, reflecting its determination that such a structure is sufficient to allow the utility to maintain its financial strength.

The cost of common equity proposed by the utility is rejected as excessively high due to its improper application of gross domestic product growth rates in its discounted cash flow model.

The revenue requirement is assigned to each class on an equal percentage of embedded cost basis. Commission rejects a proposal to set the distribution interclass revenue requirement based on risk adjusted class rates of return.

A proposed ‘environmental rate redesign‘ that would increase usage and demand charges and reduce customer charges to account for the environmental cost of producing power is rejected. Notwithstanding its concern over the environmental impact of generating electricity, the commission believes that the proposed shifting in the recovery of costs from the customer charge to the delivery charge would result in the recovery of fixed costs through variable charges and expose the utility to the risk of underrecovery.

The proposed merger of the four existing residential rate classes into a single residential delivery rate class is rejected, primarily due to the relatively large rate increases that would be faced by some customers if the classes were merged. The commission also states that it believes that in several instances there is a sufficient cost basis for maintaining separate residential rate classes.

Although it typically favors rates that are cost based, the commission finds that other considerations must be addressed in designing rates for providers of mass public transportation. Given the public interest associated with mass transit, the commission finds that rates for mass transit systems should be designed so as to minimize any changes to existing contractual terms and avoid rate shock.

Commission again departs from cost-based ratemaking in requiring the utility to define and measure the demand of large customers for billing purposes in a manner that encourages off-peak usage. The benefits of encouraging off-peak usage exceed, the commission concludes, the adverse effect associated with the somewhat higher delivery rates charged to customers that use energy during on-peak periods.

In its discussion of proposals for expanding the availability of real time pricing (RTP), the commission notes that a recently enacted state law, Public Act 94-0777, sets forth detailed requirements for utilities with 100,000 or more customers to follow in implementing RTP programs. Among other things, the new law requires such utilities to file tariffs to allow residential customers to elect RTP.

Commission finds that incremental environmental remediation costs related to the clean-up of coal tar residue at former manufactured gas plant (MGP) sites should be recovered through an environmental cost recovery adjustment rider (Rider ECR). However, non-MGP related environmental costs are excluded from Rider ECR.

Commission finds that the utility must clearly identify how much a retail customer generating facility will be compensated for excess electricity generated and sold to the utility. The utility must provide an expressly stated compensation level per kW-hr in dollars and cents, and also must offer, as an alternative to the expressly stated rate, a market-based price derived from spot prices on the Pennsylvania-New Jersey-Maryland Interconnection.

Commission caps overall administrative and general (A&G) expenses at the amount approved for the utility in its last rate case, plus an allowance for inflation. In rejecting a much larger increase proposed by the utility, the commission explains that it was unable to evaluate the reasonableness of the proposed increase inasmuch as the utility failed to provide the individual expenses contained in the A&G accounts.

The utility is authorized to recover the costs of those aspects of its incentive compensation plan that are found to confer upon ratepayers specific dollar savings or other tangible benefits.

Commission excludes estimated legal fees and expenses related to the utility's procurement case from delivery service rates, finding that those costs are not related to delivery service. Instead, the utility is permitted to recover its unamortized balance of procurement case costs through the supply administration charge.

Commission excludes from rate base a purported pension asset of $853.9 million finding, among other things, that no pension asset exists given that the pension trust is not overfunded.

State statute charges the commission with the obligation to promote retail competition. However, the commission notes that to date there has been only one competitive retail electric supplier who has sought and received authority to serve residential and small commercial customers. As such, the commission finds that it must take steps to encourage more retail electric suppliers to enter the Illinois market.

P.U.R. Headnote and Classification

1.
RATES

s120.1
Il.C.C. 2006
[ILL.] Reasonableness - Test period - Historical test year.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

2.
VALUATION

s280
Il.C.C. 2006
[ILL.] Electric utility - Rate base - Uncontested elements - Capital project additions - Pro forma capital additions and construction work in progress - Pro forma ‘new business‘ capital additions and revenue credit against operating expenses.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

3.
EXPENSES

s120
Il.C.C. 2006
[ILL.] Electric utility - Operating expenses - Uncontested elements.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

4.
RATES

s321
Il.C.C. 2006
[ILL.] Electric rate design and tariffs - Delivery service - Uncontested elements.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

5.

APPORTIONMENT

s43
Il.C.C. 2006
[ILL.] Joint expenses of associated companies - Service company allocation factors - Reporting requirements - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

6.
INTERCORPORATE RELATIONS

s13
Il.C.C. 2006
[ILL.] Holding companies and affiliated interests - Repeal of Public Utilities Holding Company Act - New state reporting requirements - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

7.
INTERCORPORATE RELATIONS

s14.2
Il.C.C. 2006
[ILL.] Intercorporate arrangements and payments - Holding companies and affiliated interests - Repeal of Public Utilities Holding Company Act - New state reporting requirements - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

8.
EXPENSES

s83
Il.C.C. 2006
[ILL.] Service company allocations - New state reporting requirements - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

9.
MONOPOLY AND COMPETITION

s54
Il.C.C. 2006
[ILL.] Retail electric suppliers - Single bill option - Modifications to delivery company business processes.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

***163** 10.
PAYMENT

s17
Il.C.C. 2006
[ILL.] Retail electric suppliers - Single bill option - Modification to delivery company business processes.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

11.
MONOPOLY AND COMPETITION

s54
Il.C.C. 2006
[ILL.] Customer choice - Switching rules - Minimum stay requirement - Provision of information by delivery utility to retail electric suppliers.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

12.
EXPENSES

s118
Il.C.C. 2006
[ILL.] Uncollectibles - Allocation between supply and delivery customers - Electric rate proceeding.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

13.
VALUATION

s107
Il.C.C. 2006
[ILL.] Depreciation and amortization reserve - Method of determination - Test year rate matching principles - Electric rate proceeding.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

14.
VALUATION

s280
Il.C.C. 2006
[ILL.] Electric utility - Delivery service rate base - General and intangible plant - Functionalization and amount - Direct assignment of costs - Rejection of proposed disallowances.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

15.
VALUATION

s361
Il.C.C. 2006
[ILL.] Electric utility - Delivery service rate base - Intangible plant - Functionalization and amount - Direct assignment of costs - Rejection of proposed disallowances.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

16.
APPORTIONMENT

s54
Il.C.C. 2006
[ILL.] Electric - Delivery services rate base - Assignment and allocation of general and intangible plant - Direct assignment.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

17.
VALUATION

s192
Il.C.C. 2006
[ILL.] Purported pension asset - Contribution to pension fund by corporate parent - Grounds for exclusion - Pension trust not overfunded - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

18.
EXPENSES

s49
Il.C.C. 2006
[ILL.] Pension expense - Allowance based on updated actuarial study - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

19.
VALUATION

s192.1
Il.C.C. 2006
[ILL.] Accumulated deferred income taxes - Subtraction from plant balances - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

20.
VALUATION

s251

Il.C.C. 2006
[ILL.] Customer deposits - Proposed rate base reduction - Grounds for denial - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

21.
VALUATION

s280
Il.C.C. 2006
[ILL.] Electric utility - Materials and supplies inventory - Last day of test year balance.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

22.
VALUATION

s142
Il.C.C. 2006
[ILL.] Legal fees and expenses - Procurement case expense - Rate case expense - Rate base effects - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

23.
EXPENSES

s89
Il.C.C. 2006
[ILL.] Regulation - Procurement case expense - Recovery mechanism - Supply administration charge - Exclusion from delivery service rates - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

24.
RATES

s332
Il.C.C. 2006
[ILL.] Electric rate design - Supply administration charge - Cost elements - Procurement case expense - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

***164** 25.
VALUATION

s280
Il.C.C. 2006
[ILL.] Electric utility - Gross utility plant - Additions and deductions - Approved delivery service rate base.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

26.
EXPENSES

s120
Il.C.C. 2006
[ILL.] Electric utility - Distribution operation and maintenance - Proposed adjustment for future, incremental decreases - Grounds for denial - Not known and measurable.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

27.
EXPENSES

s42
Il.C.C. 2006
[ILL.] Pension expense - Actuarially-determined expense - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

28.

EXPENSES

s120
Il.C.C. 2006
[ILL.] Electric utility - Administrative and general (A&G) expenses - Rejection of increase proposed by utility - Grounds - Failure to provide individual expenses contained in A&G accounts - Lack of rationale for increase.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

29.
EXPENSES

s120
Il.C.C. 2006
[ILL.] Electric utility - Administrative and general expenses - Increase limited to amount approved in last rate case plus inflation.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

30.
EXPENSES

s10
Il.C.C. 2006
[ILL.] Ascertainment - Allowance for inflation - Administrative and general expenses - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

31.
APPORTIONMENT

s23
Il.C.C. 2006
[ILL.] Electric - Delivery services expenses - Functionalization of administrative and general expenses - Use of general labor allocator.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

32.
EXPENSES

s120
Il.C.C. 2006
[ILL.] Electric utility - Delivery services revenue requirement - Functionalization of administrative and general expenses - Use of general labor allocator.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

33.
APPORTIONMENT

s43
Il.C.C. 2006
[ILL.] Joint expenses of associated companies - Corporate governance expense - General services agreement not controlling - Adjustment to reflect actual inputs in place of estimates - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

34.
EXPENSES

s83
Il.C.C. 2006
[ILL.] Payments by utility to affiliate - Corporate governance expense - Rate-making allowance - General services agreement not controlling - Adjustment to reflect actual inputs in place of estimates.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

35.
EXPENSES

s83

Il.C.C. 2006
[ILL.] Allocations from affiliate - Provision of centralized services - Business service company expense - Energy delivery shared services costs - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

36.
EXPENSES

s120
Il.C.C. 2006
[ILL.] Electric utility - Centralized services - Business service company expense - Energy delivery shared services costs - Allocation from affiliate - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

37.
EXPENSES

s95
Il.C.C. 2006
[ILL.] Salaries and wages - Method of determination - Accounting for variances in employment levels - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

38.
EXPENSES

s95
Il.C.C. 2006
[ILL.] Salaries and wages - Severance expense - Costs incurred in ordinary course of business - Determination of recurring costs - Exclusion of abnormal year - Five-year average - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

***165** 39.
EXPENSES

s95
Il.C.C. 2006
[ILL.] Salaries and wages - Severance expense - Costs flowing from defined cost savings initiative - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

40.
EXPENSES

s106
Il.C.C. 2006
[ILL.] Savings in operation - Severance associated with defined cost savings initiative - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

41.
EXPENSES

s105
Il.C.C. 2006
[ILL.] Incentive compensation - Earnings-per-share funding measure - Grounds for disallowance - Failure to demonstrate tangible benefit to ratepayers - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

42.
EXPENSES

s105
Il.C.C. 2006
[ILL.] Incentive compensation - Funding measures related to operational performance - Grounds for allowing - Tangible benefits to ratepayers - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

43.
EXPENSES

s118
Il.C.C. 2006
[ILL.] Uncollectible accounts - Use of five-year average - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

44.
EXPENSES

s46
Il.C.C. 2006
[ILL.] Charitable contributions - Allowance of reasonable donations for public welfare or charitable purposes - Disallowance of contributions associated with lobbying or political activities - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

45.
EXPENSES

s88
Il.C.C. 2006
[ILL.] Political and lobbying expenditures - Disallowance - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

46.
EXPENSES

s106
Il.C.C. 2006
[ILL.] Savings in operation - Proposed adjustment for projected savings from pending merger - Grounds for denial - Savings not known and measurable - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

47.
EXPENSES

s120
Il.C.C. 2006
[ILL.] Electric utility - Total revenue required for income deficiency - Gross revenue conversion factor.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

48.
EXPENSES

s76
Il.C.C. 2006
[ILL.] Contingency payments to tax consultants - Grounds for denial - No ratepayer benefit - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

49.
EXPENSES

s63
Il.C.C. 2006
[ILL.] Employee arbitration settlements - True-up credit - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

50.
REVENUES

s2
Il.C.C. 2006

[ILL.] Forecasts - Weather normalization of test year billing determinants - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

51.
REVENUES

s5
Il.C.C. 2006
[ILL.] Electric utility - Delivery service rate case - Non-delivery service revenues - No effect on revenue requirement.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

52.
REVENUES

s5
Il.C.C. 2006
[ILL.] Electric utility - Delivery services operating expense statement - Approved revenues.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

53.
EXPENSES

s120
Il.C.C. 2006
[ILL.] Electric utility - Delivery services operating expense statement - Approved expenses.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

54.
RETURN

s26.1
Il.C.C. 2006
[ILL.] Reasonableness - Capital structure for rate making - Actual versus imputed structure - Cost elements - Positions of the parties - Electric utility - Delivery service ***166** revenue requirement.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

55.
RETURN

s26.1
Il.C.C. 2006
[ILL.] Capital structure for rate making - Just and reasonable standard - Exclusion of costs associated with affiliates - Electric utility - Delivery service revenue requirement.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

56.
RETURN

s26.1
Il.C.C. 2006
[ILL.] Reasonableness - Capital structure - Cost elements - Goodwill asset generated by transfer of nuclear power plants - Grounds for exclusion - Not related to regulated activities - Electric utility - Delivery service rate proceeding.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

57.
RETURN

s26.1
Il.C.C. 2006
[ILL.] Reasonableness - Hypothetical structure - Adoption of structure deemed sufficient to maintain financial strength - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

58.
RETURN

s26.2
Il.C.C. 2006
[ILL.] Reasonableness - Cost of long-term debt - Use of actual rather than hypothetical cost - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

59.
RETURN

s26.2
Il.C.C. 2006
[ILL.] Reasonableness - Cost of long-term debt - Straight line amortization of unamortized loss on reacquired debt - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

60.
RETURN

s26.4
Il.C.C. 2006
[ILL.] Reasonableness - Cost of common equity - Estimation methodologies - Positions of the parties - Electric rate proceeding.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

61.
RETURN

s26.4
Il.C.C. 2006
[ILL.] Reasonableness - Cost of common equity - Discounted cash flow analysis - Appropriate growth rate - Rejection of economy-wide gross domestic product growth rate - Electric rate proceeding.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

62.
RETURN

s26.4
Il.C.C. 2006
[ILL.] Reasonableness - Cost of common equity - Method of determination - Proposed use of investment bank analysis - Grounds for rejection - Electric rate proceeding.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

63.
RETURN

s26.4
Il.C.C. 2006
[ILL.] Reasonableness - Cost of common equity - Method of determination - Proposed imposition of strict market-to-book regime - Grounds for rejection - Electric rate proceeding.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

64.
RETURN

s26.4
Il.C.C. 2006
[ILL.] Reasonableness - Cost of common equity - Electric rate proceeding.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

65.
RETURN

s87
Il.C.C. 2006
[ILL.] Electric utility - Overall cost of capital - Reasonableness.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

66.
RATES

s143
Il.C.C. 2006
[ILL.] Reasonableness - Cost of service issues - Interclass revenue allocation - Rate design - Embedded cost of service study - Electric rate proceeding.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

67.
APPORTIONMENT

s23
Il.C.C. 2006
[ILL.] Electric delivery service - Allocation of distribution and customer-related costs - Embedded cost of service study.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

68.
RATES

s321
Il.C.C. 2006
[ILL.] Electric delivery service - Potential use of marginal costs in setting distribution rates - Discussion.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

***167** 69.
RATES

s321
Il.C.C. 2006
[ILL.] Electric delivery service - Allocation of jurisdictional revenue requirement - Residential and nonresidential classes - Embedded cost of service study.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

70.
APPORTIONMENT

s11
Il.C.C. 2006
[ILL.] Distribution costs - Allocation methodology - Rejection of minimum distribution or zero intercept approach - Electric rate proceeding.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

71.
APPORTIONMENT

s23
Il.C.C. 2006
[ILL.] Electric - Distribution costs - Allocation methodology - Rejection of minimum distribution or zero intercept approach.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

72.
RATES

s321
Il.C.C. 2006
[ILL.] Electric rate design - Distribution costs - Allocation methodology - Rejection of minimum distribution or zero intercept approach.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

73.
APPORTIONMENT

s11
Il.C.C. 2006
[ILL.] Distribution costs - Allocation methodology - Use of non-coincident peak demands and coincident peak demands - Possible future use of peak and average factor - Electric rate proceeding.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

74.
APPORTIONMENT

s23
Il.C.C. 2006
[ILL.] Electric - Distribution costs - Allocation methodology - Use of non-coincident peak demands and coincident peak demands - Possible future use of peak and average factor - Electric rate proceeding.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

75.
RATES

s321
Il.C.C. 2006
[ILL.] Electric rate design - Distribution costs - Allocation methodology - Use of non-coincident peak demands and coincident peak demands - Possible future use of peak and average factor - Electric rate proceeding.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

76.
RATES

s321
Il.C.C. 2006
[ILL.] Electric rate design - Revenue allocation - Equal percentage of embedded cost basis - Rejection of risk adjusted class rate of return methodology - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

77.
RATES

s351
Il.C.C. 2006
[ILL.] Electric rate design - Residential delivery service - Proposed merger of four existing classes - Grounds for denial - Large percentage increase for some customers - Cost differences.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

78.
RATES

s349
Il.C.C. 2006
[ILL.] Electric rate design - Railroad traction power customers - Post-transition period rates - Non-cost factors - Respect for contractual obligations - Avoiding rate shock - Public policy considerations.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

79.
RATES

s344
Il.C.C. 2006
[ILL.] Electric rate design - Municipal and public use - Mass public transportation systems - Post-transition period rates - Non-cost factors - Avoiding rate shock - Respect for contractual obligations - Public policy considerations.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

80.
RATES

s339
Il.C.C. 2006
[ILL.] Electric rate design - Non-residential delivery service - Very large load standard voltage customers - Retention of separate rate class for customers with demands greater than 10 megawatts.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

81.
RATES

s339
Il.C.C. 2006
[ILL.] Electric rate design - Delivery service - High voltage class - Proposed extension of high voltage discount to low voltage loads - Grounds for denial.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

***168** 82.
RATES

s330
Il.C.C. 2006
[ILL.] Electric rate design - Delivery service - High voltage class.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

83.
RATES

s321
Il.C.C. 2006
[ILL.] Electric rate design - Delivery service - Proposed environmental rate redesign - Customer charge decrease - Corresponding increased usage and demand charges - Grounds for denial - Unwarranted shift in cost recovery - Risk of underrecovery.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

84.
RATES

s336
Il.C.C. 2006
[ILL.] Electric rate design - Delivery service - Proposed environmental rate redesign - Customer charge decrease - Corresponding increased usage and demand charges - Grounds for denial - Unwarranted shift in cost recovery - Risk of underrecovery.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

85.
RATES

s322
Il.C.C. 2006
[ILL.] Electric rate design - Delivery service - Demand and load - Proposed environmental rate redesign - Customer charge decrease - Corresponding increased usage and charges - Grounds for denial - Unwarranted shift in cost recovery - Risk of underrecovery.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

86.
EXPENSES

s11
Il.C.C. 2006
[ILL.] Unexpected, volatile, or fluctuating costs - Recovery through rider mechanism - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

87.
AUTOMATIC ADJUSTMENT CLAUSES

s34
Il.C.C. 2006
[ILL.] Environmental cost recovery rider - Incremental remediation costs related to clean-up of coal tar at manufactured gas plant sites - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

88.
EXPENSES

s20
Il.C.C. 2006
[ILL.] Environmental remediation costs - Clean up of coal tar at manufactured gas plant sites - Incremental costs - Recovery through rider mechanism - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

89.
EXPENSES

s120
Il.C.C. 2006
[ILL.] Electric utility - Incremental environmental remediation costs - Clean up of coal tar at manufactured gas plant sites - Recovery through rider mechanism.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

90.
RATES

s332
Il.C.C. 2006
[ILL.] Electric rate design - Special charges - Incremental environmental remediation costs - Clean up of coal tar at manufactured gas plant sites - Recovery through rider mechanism.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

91.
EXPENSES

s20
Il.C.C. 2006
[ILL.] Environmental remediation costs - Clean up of sites other than manufactured gas plant sites - Base rate recovery - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

92.
EXPENSES

s120
Il.C.C. 2006
[ILL.] Electric utility - Environmental remediation costs - Clean up of sites other than manufactured gas plant sites - Base rate recovery - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

93.
RATES

s322
Il.C.C. 2006
[ILL.] Electric rate design - Demand and load - Direct load control of air conditioners - Monthly discount during summer.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

94.
RATES

s322
Il.C.C. 2006
[ILL.] Electric rate design - Demand response riders - Modification or elimination - Restructuring from vertically integrated to delivery service utility - Compatibility of riders with generation procurement process.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

95.
RATES

s339
Il.C.C. 2006
[ILL.] Electric rate design - Nonresidential***169** space heating - Cost-based rate - Elimination of discount on delivery service charges.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

96.
RATES

s332
Il.C.C. 2006
[ILL.] Electric rate design - Non-standard delivery service - Proposed reserved distribution system capacity charge - Grounds for denial - Potential for recovery of additional delivery charges not approved by commission.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

97.
RATES

s349
Il.C.C. 2006
[ILL.] Electric rate design - Mass transit customers - Non-standard delivery service - Proposed reserved distribution system capacity charge - Grounds for denial - Potential for recovery of additional delivery charges not approved by commission.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

98.
RATES

s339
Il.C.C. 2006
[ILL.] Electric rate design - Non-standard delivery service - Customers who have installed their own transformers - Continuation of credit.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

99.
COGENERATION

s25
Il.C.C. 2006
[ILL.] Avoided cost rates - Self-generation - Utility purchases from retail customer generating facilities - Standard energy payment - Expressly stated compensation level - Market-based pricing option.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

100.
COGENERATION

s30
Il.C.C. 2006
[ILL.] Avoided cost rates - Self-generation - Utility purchases from retail customer generating facilities - Standard energy payment - Methods of computation.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

101.
ELECTRICITY

s4
Il.C.C. 2006
[ILL.] Resource procurement - Self-generation - Utility purchases from retail customer generating facilities - Standard energy payment - Methods of computation.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

102.
RATES

s344
Il.C.C. 2006
[ILL.] Electric rate design - Governmental consolidated billing - Retention with revisions - Tracking of any revenue shortfall.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

103.
RATES

s332
Il.C.C. 2006
[ILL.] Electric rate design - Special charges - Meter rental charges.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

104.
RATES

s339
Il.C.C. 2006
[ILL.] Electric rate design - Resale or redistribution by customer to third persons - Sales by landlord to tenants - Terms and conditions.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

105.
SERVICE

s169
Il.C.C. 2006
[ILL.] Resale or redistribution by customer to third persons - Sales by landlord to tenants - Terms and conditions - Electricity.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

106.
RATES

s349
Il.C.C. 2006
[ILL.] Electric rate design - Railroad traction power customers - Bundled basic electric service.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

107.
RATES

s323
Il.C.C. 2006
[ILL.] Electric rate design - Delivery service - Demand and load - Measuring and defining demand for billing purposes - Large customers - Deviation from cost-based ratemaking - Encouraging off-peak usage of electricity.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

108.
RATES

s344
Il.C.C. 2006
[ILL.] Electric rate design - Municipal pumping class - Proposed aggregation of demand - Grounds for denial - Inconsistency with cost-based rates.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

109.
RATES

s344
Il.C.C. 2006
[ILL.] Electric rate design - Delivery service - Municipal customer - Mass transit ***170** authority - Proposed credit for customer-owned transformation, conversion and distribution facilities - Grounds for denial - Failure to demonstrated significant benefits.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

110.
RATES

s349
Il.C.C. 2006
[ILL.] Electric rate design - Delivery service - Mass transit authority - Proposed credit for customer-owned transformation, conversion and distribution facilities - Grounds for denial - Failure to demonstrated significant benefits.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

111.
RATES

s332
Il.C.C. 2006
[ILL.] Electric rate design - Supply administrative charge - Recovery of costs of administering supply function for bundled electric service customers - Method of calculation - Two-step allocation process.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

112.
RATES

s339
Il.C.C. 2006
[ILL.] Electric rate design - Bundled service customers - Recovery of costs of administering supply function - Supply administration charge - Two-step allocation process.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

113.
ELECTRICITY

s4
Il.C.C. 2006
[ILL.] Demand response programs - Real time pricing for residential customers - Statutory requirements.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

114.
RATES

s326
Il.C.C. 2006
[ILL.] Electric rate design - Real time pricing for residential customers - Program implementation - Statutory requirements.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

115.
SERVICE

s320
Il.C.C. 2006
[ILL.] Electric utilities - Residential service - Real time pricing option - Statutory requirements.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

116.

EXPENSES

s120
Il.C.C. 2006
[ILL.] Electric utility - Nonstandard service required by local government unit - Incremental costs - Direct recovery from customers within boundaries of local government unit - Local government compliance rider.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

117.
RATES

s332
Il.C.C. 2006
[ILL.] Electric rate design - Special charges - Local governmental compliance rider - Incremental costs of nonstandard service required by local government unit - Direct recovery from customers within boundaries of local government unit.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

118.
EXPENSES

s69
Il.C.C. 2006
[ILL.] Maintenance of facilities - Nonstandard service required by local government unit - Incremental costs - Direct recovery from customers within boundaries of local government unit - Local government compliance rider - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

119.
ELECTRICITY

s4
Il.C.C. 2006
[ILL.] Self generators - Direct access to wholesale market - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

120.
COGENERATION

s13
Il.C.C. 2006
[ILL.] Self generators - Interconnection to transmission - Direct access to wholesale market - Pricing and cost - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

121.
RATES

s235
Il.C.C. 2006
[ILL.] Initiation of rate changes - Filing of compliance tariffs - Electric utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

122.
MONOPOLY AND COMPETITION

s54
Il.C.C. 2006
[ILL.] Electric - Customer choice of retail supplier - Switching rules.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

123.
MONOPOLY AND COMPETITION

s54
Il.C.C. 2006

[ILL.] Electric - Customer choice of ***171** retail supplier - Customer designation of general account agent.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

124.
MONOPOLY AND COMPETITION

s54
Il.C.C. 2006
[ILL.] Electric - Customer choice of retail supplier - Customer enrollment procedures - Electronic data interchange.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

125.
MONOPOLY AND COMPETITION

s54
Il.C.C. 2006
[ILL.] Electric - Customer choice of retail supplier - Access to customer usage data.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

126.
MONOPOLY AND COMPETITION

s54
Il.C.C. 2006
[ILL.] Electric - Customer choice of retail supplier - Utility communication with customers and competitors.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

127.
PAYMENT

s17
Il.C.C. 2006
[ILL.] Billing - Retail electric competition - Utility consolidated billing with purchase of receivables - Proposed compulsory provision - Grounds for denial.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

128.
MONOPOLY AND COMPETITION

s54
Il.C.C. 2006
[ILL.] Electric - Customer choice of retail supplier - Utility consolidated billing with purchase of receivables - Proposed compulsory provision - Grounds for denial.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

129.
PAYMENT

s27
Il.C.C. 2006
[ILL.] Collections - Customer choice of retail supplier - Utility consolidated billing with purchase of receivables - Proposed compulsory provision - Grounds for denial

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

130.
MONOPOLY AND COMPETITION

s54
Il.C.C. 2006
[ILL.] Electric - Customer choice of retail supplier - Utility business processes - Modifications to aid retail suppliers and customers.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

131.
MONOPOLY AND COMPETITION

s54
Il.C.C. 2006
[ILL.] Electric - Customer choice of retail supplier - Commission obligation to promote competition.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

132.
SERVICE

s321
Il.C.C. 2006
[ILL.] Electric distribution utility - Reliability performance - Staff assessment.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

133.
ELECTRICITY

s4
Il.C.C. 2006
[ILL.] Operating practices - Reliability performance - Vegetation management - Tree-trimming program - Need for improvement - Distribution utility.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

134.
SERVICE

s284
Il.C.C. 2006
[ILL.] Electric metering - Reliability performance - Staff assessment.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

135.
SERVICE

s306
Il.C.C. 2006
[ILL.] Electric metering - Reliability performance - Staff assessment.

Re Commonwealth Edison Company

P.U.R. Headnote and Classification

136.
ELECTRICITY

s4
Il.C.C. 2006
[ILL.] Demand response programs - System benefits - Customer benefits - Implementation process - Discussion.

Re Commonwealth Edison Company

Before Box, chairman.

BY THE COMMISSION:

I. PROCEDURAL HISTORY

****1** On August 31, 2005, Commonwealth Edison Company (‘ComEd‘ or ‘the Company ‘) filed with the Illinois Commerce Commission (the ‘Commission ‘), pursuant to Section 9-201 of the Public Utilities Act (the ‘Act‘) (220 ILCS 5/9-201), the following tariff sheets: ILL. C.C. No. 4, 8th Revised Sheet No. 1.01; 10th ***172** Revised Sheet No. 1.02; 4th Revised Sheet No. 1.03; 2nd Revised Sheet No. 1.04; Original Sheet No. 1.05; 45th Revised Sheet No. 9; 25th Revised Sheet No. 16; 21st Revised Sheet No. 18; 37th Revised Sheet No. 24; 41st Revised Sheet No. 28; 30th Revised Sheet No. 34; 31st Revised Sheet No. 38; 34th Revised Sheet No. 46; 34th Revised Sheet No. 49; 35th Revised Sheet No. 51; 38th Revised Sheet No. 53; 35th Revised Sheet No. 55; 4th Revised Sheet No. 55.50; 7th Revised Sheet No. 55.70; 2nd Revised Sheet No. 55.77; 3rd Revised Sheet No. 55.8; 3rd Revised Sheet No. 61.01; 1st Revised Sheet No. 61.41; 2nd Revised Sheet No. 61.61; 11th Revised Sheet No. 62; 9th Revised Sheet No. 62.10; 24th Revised Sheet No. 63; 8th Revised Sheet

No. 67; 16th Revised Sheet No. 68; 31st Revised Sheet No. 70; 8th Revised Sheet No. 71; 28th Revised Sheet No. 73; 13th Revised Sheet No. 74; 36th Revised Sheet No. 77; 28th Revised Sheet No. 79; 16th Revised Sheet No. 82; 9th Revised Sheet No. 82.10; 17th Revised Sheet No. 84; 4th Revised Sheet No. 85.01; 35th Revised Sheet No. 88; 39th Revised Sheet No. 92; 1st Revised Sheet No. 93.01; 5th Revised Sheet No. 95.05; 2nd Revised Sheet No. 95.07; 5th Revised Sheet No. 95.09.6; 4th Revised Sheet No. 109; 2nd Revised Sheet No. 140; 4th Revised Sheet No. 152; 2nd Revised Sheet No. 163; 1st Revised Sheet No. 173; 2nd Revised Sheet No. 183; 3rd Revised Sheet No. 217; 1st Revised Sheet No. 221; 2nd Revised Sheet No. 225; 2nd Revised Sheet No. 232; 1st Revised Sheet Nos. 241 and 242; Original Sheet Nos. 304 through 584; ILL. C.C. No. 9, 1st Revised Title Sheet; Amendment to Electric Service Agreement between Commonwealth Edison Company and Chicago Park District dated as of February 28, 1951, as amended; Amendment to Street Lighting Electric Service Agreement between Commonwealth Edison Company and City of Chicago dated as of February 20, 1950, as amended; Amendment to Electric Service Agreement between Commonwealth Edison Company and Chicago Transit Authority dated as of August 1, 1958, as amended; and Amendment to Electric Service Agreement between Commonwealth Edison Company and Northeast Illinois Regional Commuter Railroad Corporation dated June 1, 1986, as amended (collectively, the 'Tariffs'). This tariff filing embodied a proposed general increase in electric rates, a general restructuring of rates, price unbundling of bundled service rates, and revision of other terms and conditions of service. The tariff filing was accompanied by direct testimony, other exhibits, and other materials required under Parts 285 ('Part 285') and 286 ('Part 286 ') of Title 83 of the Illinois Administrative Code (the 'Code'), 83 Ill. Admin. Code Parts 285 and 286.

****2** Notice of the proposed tariff changes reflected in this rate filing was posted in ComEd's business offices and published in a secular newspaper of general circulation in ComEd's service area, as evidenced by publisher's certificates, in accordance with the requirements of Section 9-201(a) of the Act, 220 ILCS 5/9-201(a), and the provisions of 83 Ill. Admin. Code Part 255.

The Commission issued a Suspension Order on September 14, 2005, suspending the Tariffs to and including January 27, 2006, and initiating this proceeding. On January 25, 2006, the Commission issued a Resuspension Order, suspending the Tariffs to and including July 27, 2006.

Pursuant to notice duly given in accordance with the law and the rules and regulations of the Commission, a pre-hearing conference was held in this matter before duly authorized Administrative Law Judges (the 'ALJs') of the Commission, at its offices in Chicago, Illinois, on October 20, 2005. More than ten days prior, notice of the status hearing had been provided by the Chief Clerk of the Commission to municipalities in ComEd's service area, in accordance with the requirements of Section 10-108 of the Act, 220 ILCS 5/10-108. Subsequent pre-hearing conferences were held before the ALJs at the Commission's Chicago offices on December 8, 2005, January 19, 2006, February 9, 2006, and March 2, 2006.

On April 6, 2006, the Commission entered an Interim order granting Staff's Motion for Entry of Interim Order initiating an audit process to verify the original cost of ComEd's distribution***173** plant in service at December 31, 2004. The details of the audit process are set forth in the Interim Order.

Petitions to Intervene were filed or appearances were entered on behalf of the Attorney General of the State of Illinois (the 'Attorney General' or 'AG '); BlueStar Energy Services, Inc. ('BlueStar'); Building Owners and Managers Association of Chicago ('BOMA'); Castwell Products, Inc. ('Castwell'); Chicago Transit Authority ('CTA'); Caterpillar Inc. ('Caterpillar'), Abbott Laboratories, Inc. ('Abbott'), and Citgo Petroleum Corporation ('Citgo '); Citizens Utility Board ('CUB'); City of Chicago (the 'City'); Community Action for Fair Utility Practice ('CAFUP'); Constellation Energy Commodities Group, Inc. ('CCG'); Constellation NewEnergy, Inc. ('NewEnergy'); the Cook County State's Attorney's Office ('CCSAO') (collectively, CUB and CCSAO are 'CUB-CCSAO', CUB and the City are

'CUB-City', and CUB, CCSAO, and the City are 'CCC'); United States Department of Energy ('DOE'); Direct Energy Services, L.L.C. ('DES'); Downers Grove Sanitary District ('Downers Grove'); Dynegy Inc. ('Dynegy'); Illinois Association of Wastewater Agencies ('IAWA'); Ford Motor Company ('Ford'), Corn Products International, Inc. ('Corn Products '), Merchandise Mart Properties, Inc. ('Mart'), Sterling Steel Company, LLC ('Sterling'), and Daimler Chrysler, Inc. ('Chrysler'); ISG Riverdale, Inc. ('ISG'); MidAmerican Energy Company ('MidAmerican'); Midwest Generation EME, LLC ('Midwest Gen'); Northeast Illinois Regional Commuter Railroad Corporation, d/b/a Metra ('Metra'); Peoples Energy Services Corporation ('PES'); University of Illinois ('U. of I'); Thermal Chicago Corporation ('Thermal') (collectively, Caterpillar, Abbott, Citgo, Ford, Corn Products, Mart, Sterling, Chrysler, and Thermal are styled as the 'Illinois Industrial Energy Consumers' or 'IIEC '); and U.S. Energy Savings Corp. ('USESC') (collectively, NewEnergy, DES, MidAmerican Energy Company, PES, and USESC are the 'Coalition of Energy Suppliers' or 'CES') (collectively, all of the foregoing parties are the 'Intervenors').

****3** Pursuant to notice as required by law and the Commission's rules, evidentiary hearings were held before duly authorized Administrative Law Judges on March 21-24, March 27-30, and April 13, 2006, at the offices of the Commission in Chicago, Illinois. At the evidentiary hearings, ComEd, the Staff of the Commission ('Staff'), the AG, BOMA, CES, the City, CTA, CUB, CUB-City, CCC, IIEC, Metra, DOE, and IAWA entered appearances and presented testimony, either by live witness(es) or by affidavit(s). Appearances were also entered for New Energy, Dynegy, and Midwest Gen, although they did not submit testimony, except for NewEnergy's participation in CES. Certain additional materials were received into the record thereafter by order of the ALJs. On June 7, 2006, the ALJs marked the record 'Heard and Taken'.

The following witnesses testified on behalf of ComEd: Frank M. Clark, Jr., Chairman and Chief Executive Officer; John H. Landon, Ph.D., Special Advisor, Analysis Group, Inc.; John T. Costello, Executive Vice President and Chief Operating Officer; David D. DeCampli, Vice President, Asset Investment Strategy & Development, ComEd and Exelon Energy Delivery LLC ('EED'); Jerome P. Hill, Director of Revenue Policy; Robert W. Gee, President, GEE Strategies Group LLC; J. Barry Mitchell, President; Samuel C. Hadaway, Principal, FINANCO, Inc.; Paul R. Crumrine, Director, Regulatory Strategies & Services; Lawrence S. Alongi, Manager, Retail Rates; Timothy F. McInerney, Senior Rate Specialist; Alan C. Heintz, Vice President, Brown, Williams, Moorhead & Quinn, Inc.; Richard F. Meischeid II, Managing Principal, Towers Perrin; Kathryn M. Houtsma, CPA, Vice President, Regulatory Projects; Susan F. Tierney, Ph.D., Managing Principal, Analysis Group, Inc.; Michael J. Meehan, Director of Post-2006 Business Implementation; Allan Fernandes, Manager - Environmental Remediation, EED; and Peter McCauley, Project Manager - Environmental Remediation, EED.

The following witnesses testified on behalf of Staff: Dianna Hathhorn, Accountant, Accounting Department, Financial Analysis ***174** Division; Theresa Ebrey, Accountant, Accounting Department, Financial Analysis Division; Thomas L. Griffin, Accountant, Accounting Department, Financial Analysis Division; Sheena Kight, Senior Financial Analyst, Finance Department, Financial Analysis Division; Michael McNally, Senior Financial Analyst, Finance Department, Financial Analysis Division; Peter Lazare, Senior Rate Analyst, Rates Department, Financial Analysis Division; Mark A. Hanson, Rate Analyst, Bureau of Public Utilities; Ronald Linkenback, Electrical Engineer, Engineering Program Department, Energy Division; James D. Spencer, Senior Electrical Engineer, Engineering Department, Energy Division; John V. Stutsman, Manager, Reliability Assessment Program, Energy Division; Greg Rockrohr, Senior Electrical Engineer, Engineering Department, Energy Division; and Dr. Eric P. Schlaf, Senior Economic Analyst, Energy Division.

The AG's witnesses were David J. Effron, consultant; and Scott J. Rubin, attorney and consultant.

****4** BOMA's witnesses were T.J. Brookover, Senior

Vice President & Director of Property Management, The John Buck Company; Kristav M. Childress, Technical Director, GEV Corp.; and David W. McClanahan, President, BDL Enterprises, Inc.

CES' witnesses were Philip R. O'Connor, Ph.D., Vice President, Illinois Market, NewEnergy; John F. Clark, Director of Finance and Operations, NewEnergy; Jennifer Witt, PES; John L. Domagalski, Director of Pricing and Product Development, NewEnergy; and Mary Meffe, Chief Financial Officer, Energy Savings Income Fund.

The City's witness was Steven Walter, Deputy Commissioner for Energy Management, Department of General Services.

The CTA's witnesses were Dennis Anosike, Senior Vice President, Treasurer, Budget/Capital; and Glenn Zika, Vice President of Engineering.

CUB-City's witness was Christopher C. Thomas, Director of Policy.

CCC's witnesses were Edward C. Bodmer, consultant; Michael J. McGarry, Sr., President and Chief Executive Officer, Blue Ridge Consulting Services, Inc.; and Steven W. Ruback, Principal, The Columbia Group, Inc.

IAWA witness was Nicholas J. Menninga, Assistant General Manager, Downers Grove Sanitary District, and Chairman, IAWA Ad Hoc Energy Subcommittee.

IIEC witnesses were Robert R. Stephens, Consultant, Brubaker & Associates, Inc.; Alan Chalfant, Consultant, Brubaker & Associates, Inc.; Michael Gorman, Consultant, Energy Advisor, and Managing Principal, Brubaker & Associates, Inc.; and Brian A. Janous, Consultant, Brubaker & Associates, Inc.

DOE's witness was Dr. Dale E. Swan, Senior Economist and Principal, Exeter Associates, Inc.

Metra's witness was James Mitchell, Director Energy Management.

II. UNCONTESTED ISSUES

A. ISSUES THAT NO PARTY CONTESTED

1. Test Year

[1] ComEd selected the historical test year of 2004. No party contests the use of 2004 as the test year.

2. Elements of Rate Base

a) 21 Capital Project Additions

[2] The ‘21 capital project additions‘ references the 21 largest additions to rate base by ComEd since its last rate case. This includes but is not limited to Distribution Plant, General Plant and Intangible Plant projects. No party contests the inclusion of these 21 additions in rate base.

b) Pro Forma Capital Additions and Construction Work in Progress

When ComEd has construction works in progress, it does not accrue Allowance for Funds Used During Construction (‘AFUDC‘) for those construction works. Originally ComEd***175** proposed that $53,449,000 (corrected) be included in rate base for non-AFUDC bearing Construction Work in Progress (‘CWIP‘). Staff witness Mr. Griffin (Staff Ex. 3.0) and CCC witness Mr. McGarry (CCC Ex. 2.0) both objected on the grounds that this constituted costs being ‘double counted‘ with certain *pro forma* capital additions. ComEd, Staff and CCC have now come to the agreement that ComEd will lower the amount of CWIP in its rate base from $53,449,000 to $41,047,000. As a result Staff and CCC have withdrawn their proposed adjustments to CWIP and the *pro forma* capital additions. Accordingly, this issue is not contested.

****5** *c) Pro Forma ‘New Business‘ Capital Additions and Revenue Credit Against Operating Expenses*

CCC and AG recommended an adjustment to ComEd's *pro forma* new business capital additions on the theory that the revenue requirement did not reflect revenues that would result from the additions. ComEd, CCC, and the AG came to the agreement that ComEd would add a revenue credit of $13,751,325 to its revenue requirement and CCC and the AG would withdraw their proposed adjustments to rate base on this issue. Therefore, this issue is no longer contested.

3. Elements of Operating Expenses

a) Advertising Expense Adjustment

[3] Through direct and rebuttal testimony, ComEd and Staff agreed to remove $317,000 of ‘advertising expenses‘ from the revenue requirement. Accordingly, this issue is no longer contested.

b) Staff 2005 Wage and Salary Adjustment

Through direct and rebuttal testimony, ComEd and Staff agreed to remove $1,174,000 of ComEd's *pro forma* salary and wage increases adjustment of 2005. Accordingly, this issue is no longer contested.

c) Post-Retirement Healthcare Benefits

The AG, in its direct testimony, suggested a $7,636,000 downward adjustment to reduce pension and post-retirement health care expenses in the test year to remove the impact of fair value accounting. ComEd then proposed, based on updated data, a $5,200,000 adjustment to pension and post-retirement expense would be appropriate and consistent with fair value adjustments to the capital structure proposed by ComEd. The AG subsequently agreed to the $5,200,000 figure. Although ComEd did not agree that it would be appropriate to record a regulatory liability, ComEd agreed that its actuaries would maintain the data necessary to evaluate the impact of fair value adjustments to pension and post-retirement health care expenses in the future. No other party contested the adjustment.

d) Tax Consultants

In the interest of narrowing the issues ComEd agreed to the AG's proposal that a $4,460,000 charge for payments to tax consultants in 2004 be removed. Accordingly, this issue is no longer contested.

e) Employee Arbitration Settlements

The AG had recommended an adjustment to eliminate certain employee arbitration settlement costs. In the interest of narrowing the issues ComEd recommended to reduce their test year employee/arbitration costs by $4,301,224 to account for a true-up credit booked in 2005. The AG agreed to this adjustment. Accordingly, this issue is no longer contested.

4. Elements of Rate Design and Tariffs

a) Rider PM

[4] No party takes issue with ComEd's proposed Rider PM. The Commission therefore concludes that Rider PM is reasonable and it is hereby approved.

***176** *b) Rider MSP7*

No party objects to ComEd's proposed Rider MSP7. The Commission concludes that Rider MSP7 is reasonable and it is hereby approved.

c) Rate RESS7

No party objected to or proposed revisions to ComEd's proposed Rate RESS7; thus, the Commission concludes Rate RESS7 is reasonable and it is hereby approved.

d) Rider FCA

****6** The Commission review of the record indicates that no party takes issue with ComEd's proposed Rider FCA. The Commission finds Rider FCA to be reasonable and it is hereby approved.

e) Rider RCA

No party took issue with ComEd's proposed Rider RCA.

The Commission therefore finds that Rider RCA is reasonable and it is hereby approved.

5. Other Issues

a) Exelon GSA-Reporting Requirements

[5-9] As a result of the repeal of the Public Utilities Holding Company Act (‘PUHCA‘), Staff proposed new reporting requirements. Staff modified its original proposal and ComEd agreed to the following: ComEd will file a copy of its FERC Form 60 with the ICC and provide a copy to the Manager of Accounting on the day it is filed with the FERC; ComEd will notify the ICC within 30 days of implementation of substantial changes to service company allocation factors. [FN1] Finally, ComEd will file as part of its ICC Form 21 a report of BSC corporate governance charges by function, along with the schedules that were previously filed as part of the U-13-60 report filed with the Securities and Exchange Commission prior to the repeal of PUHCA, with detail to be provided for items that exceed $100,000in amount. [FN2]

The Commission finds this to be reasonable and directs ComEd to comply with the reporting requirements proposed by Staff and agreed to by ComEd.

B. PROPOSALS TO WHICH CERTAIN PARTIES HAVE AGREED

1. Elimination of Rate 87

Staff and ComEd have reached agreement that elimination of Rate 87 is appropriate, provided that proper notice is provided to the City of Rockford before canceling the tariff. The Commission hereby directs ComEd to provide proper notice to the City of Rockford as required by the currently effective Rate 87. Contingent upon providing proper notice, ComEd is authorized to cancel Rate 87 effective January 2, 2007.

2. Condominium Common Area Reclassification

No party objects to ComEd's proposed tariff revisions regarding the reclassification of certain condominium common area customer accounts from residential to nonresidential customers consistent with statements made by ComEd in Docket No. 05-0159.Therefore the Commission finds the changes to be appropriate and the revisions are hereby approved.

3. Modifications to ComEd Business Processes to Aid RESs and Customers

a) Rider SBO7

[10-13] The proposed Single Bill Credit 7 contained in Rate RDS is an update of the current cost-based fixed credit, the Single Bill Credit, using the methodology approved in ComEd's last delivery service rate case, Docket 01-0423.

ComEd originally proposed that Rider SBO7 provide that once the Retail Electric Supplier (‘RES‘) terminates the single bill option ***177** for a customer, the RES no longer would be able to provide the single bill option to that customer for a 12-month period. As a result, many customers would have received two bills - one from ComEd and the other from the RES. The Coalition of Energy Suppliers (‘CES‘) recommended that Rider SBO7 be revised so that customers have greater access to the convenience of receiving a single bill from a RES under ComEd's Rider SBO7. In response to concerns raised by CES, ComEd agreed to make certain revisions to Rider SBO7. ComEd is willing to eliminate the provision in proposed Rider SBO7 that precludes a RES from offering SBO service to a retail customer during the 12 monthly billing periods after it terminated such service. However, ComEd wants to reserve the right to revisit this matter should unforeseen issues arise. CES is satisfied with the modifications proposed by ComEd. ComEd Exhibit 41.6 contains the amendment to proposed Rider SBO7 that would implement this revision. Rider SBO7 as amended is reasonable and is approved by the Commission.

b) Definition of ‘New Customer‘

****7** When an Account is ‘finaled‘ by ComEd, the existing customer Account Number is terminated from

ComEd's system and the retail customer is sent a 'Final Bill.' CES requested that ComEd modify the definition of a 'new customer' so that an existing customer account would not be 'finaled' as a result of a name change. ComEd agreed to change the definition of 'new customer' in the manner requested by CES. No other party contested this issue. Subject to this modification, ComEd's definition of 'New Customer' is approved by the Commission.

c) Definition of retail versus wholesale peak and off-peak periods

CES raised certain concerns about the definition of 'Peak-Period,' under ComEd's proposed General Terms and Conditions. ComEd proposed to make amendments to some of the Definitions in its proposed General Terms and Conditions to distinguish the retail peak and off-peak periods from the wholesale peak and off-peak periods used by PJM Interconneted LLC ('PJM '). ComEd proposed changes to the definitions of the following terms: PJM Peak Period; PJM Off-Peak Period; Retail Peak Period; and Retail Off-Peak Period. CES accepted the revised definitions presented by ComEd and recommended that the Commission approve the revisions. No other party contested these changes. The amendments to the definitions are reasonable and approved by the Commission.

d) Clarification of Switching Rules

CES originally took the position that the switching rules in ComEd's proposed tariffs are complex and unclear. ComEd provided testimony that it is taking steps to educate customers and RESs to ease the transition to these new tariffs, including revising its RES Handbook and its Customer Handbook. ComEd states that clear and easy-to-follow rules will reduce unnecessary expenditures of time and effort by customers. These handbooks will be available to interested parties within approximately two months after the completion of this Docket. ComEd also states that it is willing to work with RESs to develop a summary of the switching rules for purposes of this RES Handbook. In addition, ComEd agreed to amend the 12-month restriction in Rate RCDS as a one-time transition provision such that a customer could switch to delivery service on its last regularly scheduled meter reading date in 2006. CES is satisfied with ComEd's proposals regarding switching rules. The Commission finds this proposal to be reasonable and directs ComEd to file an appropriate revision of Rate RCDS with its compliance filing.

e) Timely Revision to RES Handbook

ComEd agrees to revise its RES Handbook and its Customer Handbook and make them available to interested parties, within two months after the completion of this Docket. As stated in Section II.B.3.d, *supra*, the Commission***178** finds this to be reasonable. ComEd shall also submit a copy the RES Handbook and Customer Handbook to Staff once they are made available to interested parties.

f) Inclusion of 'Frequently Asked Questions' on PowerPath'

****8** CES requested that ComEd establish an electronic bulletin board for customers and RESs to interact with ComEd, and dedicate employees to address RES customer's service questions. ComEd agreed that it would post common RES questions and responses as FAQs on the PowerPath website. CES agreed to this proposal. No other party contests this issue.

g) Relief From Minimum Stay Requirement

Under ComEd's current tariffs, customers who have returned from competitive supply to a ComEd bundled rate are required to remain on that bundled rate for a minimum of twelve (12) months. ComEd agreed with CES that it is appropriate to provide for a one-time exception to the 12-month restriction, so that customers who return to ComEd bundled service in 2006 would be allowed to exit bundled service and elect delivery service at the last meter reading in calendar year 2006 (rather than requiring the customer to remain on bundled service until the first meter reading date in 2007). ComEd submitted proposed tariff sheets to memorialize this agreement. No other party commented on this proposal.

h) Provision of Information to RESs

(i) 867 and 810 Billing Data available after 1:00 PM

An EDI 867 transaction provides detailed meter usage information and is sent to RESs when an account is billed. The EDI 810 transaction is the bill image of ComEd's delivery service bill, and is sent to a RES that is a customer's Single Bill Option provider under ComEd's Rider SBO - Single Bill Option ('SBO') when an account is billed. CES requested that ComEd make 867 and 810 Billing Data available electronically before 1:00 PM for same-day processing by RESs, and data submitted after 1:00 PM will be dated the next business day. ComEd agreed to this request, and has modified its systems on January 12, 2006. No other party contested this issue.

(ii) Weekly Pending Disconnection Report

CES requested that ComEd provide all drop information to RESs electronically, in real time. ComEd agreed to provide information to RESs regarding pending disconnections through a hard copy report, which could be provided on a weekly basis and CES agreed to this resolution. No other party contested this issue. The Commission notes that this issue is further addressed *infra* in the discussion of Customer Choice and Retail Supplier Issues.

(iii) Customer Current Rate and Supply-Type Information on PowerPath

CES requested that ComEd provide current rate and supply-type information, including customer supply group and customer delivery class information, on ComEd's PowerPath website. ComEd agreed that it will implement these changes in the near future. No other party contested this issue.

(iv) DASR Eligibility on PowerPath

CES requested that ComEd provide a Direct Access Service Request ('DASR ') eligibility date on its PowerPath website. ComEd agreed that a DASR eligibility date would be beneficial to the market participants, and agreed that, if the data is readily available, ComEd will make this information available to requestors with proper authority. No other party contested this issue.

(v) Customers' TOU data on PowerPath

****9** CES requested that ComEd provide 'time of use' ('TOU') data and on- and off-peak splits. ComEd agreed to provide TOU data ***179** relating to how ComEd defines peak and off-peak service for some customers and agreed to provide such information on the PowerPath website to RESs. CES agreed to this proposal. No other party contested this issue.

(vi) Allocation of Uncollectible Expenses

CES raised the issue of the Uncollectible Adjustment Factor as it applies to Supply Charges under the Bundled Electric Service-BES tariffs. ComEd proposed to allocate uncollectible expenses between electric supply and delivery customers. The parties then discussed how each of the four Uncollectibles Adjustment Factors for each of the BES tariffs was determined. CES and ComEd are in agreement on this issue. No other party contested this issue.

CONTESTED ISSUES

The position statements for the following issues are provided by each party. The scope of the conclusions reached herein is defined by the underlying record and not the position statements offered by the parties.

III. RATE BASE

1. DEPRECIATION AND AMORTIZATION RESERVE ComEd

[14] ComEd states that, based on the 2004 plant balances plus the *pro forma* capital additions included in its proposed rate base, the correct figure for Accumulated Reserve for Amortization and Depreciation (the ‘Depreciation Reserve‘) is $4,595,475,000. (*E.g.*, Hill Dir., ComEd Ex. 5.0 Corr., 14:284-293; ComEd Ex. 5.1 at Sched. B-1 Errata; Hill Sur., ComEd Ex. 36.0 Corr. at Sched. 1 Rev., p. 4).

According to ComEd, it made the appropriate and complete *pro forma* adjustments to the Depreciation Reserve for the post-test year plant that comprises its *pro forma* capital additions, consistent with Part 287 of Title 83 of the Illinois Administrative Code (‘Part 287‘). That section defines *pro forma* adjustments to a historical test year as ‘changes affecting the ratepayers in plant investment, operating revenues, expenses, and cost of capital where such changes occurred during the selected historical test year or are reasonably certain to occur subsequent to the historical test year within 12 months after the filing date of the tariffs and where the amounts of the changes are determinable.‘ (83 Ill. Adm. Code § 287.40). In addition, ComEd noted that Section 287.40 also provides that ‘[a]ttrition or inflation factors shall not be substituted for a specific study of individual capital, revenue, and expense components.‘

ComEd avers that AG witness David Effron's proposed adjustment - to increase through the end of 2005 the entire Depreciation Reserve pertaining to all plant that went into service prior to and in the 2004 test year (Effron Dir., AG Ex. 1.0, 8:8-14) - in effect would make the test year Depreciation Reserve not the 2004 historical test year value, but, for this component of rate base only, a 2005 value. (*E.g.*, Hill Reb., ComEd Ex. 19.0 Corr., 13: 245-51). ComEd witnesses testified that Mr. Effron's adjustment, if accepted, would increase the Depreciation Reserve of $4,595,475,000 in ComEd's rate base by $259,246,000 (after assignment to reselling municipalities). (Hill Sur., ComEd Ex. 36.0 Corr., Sched. 1 Rev., p. 4; Effron, AG Ex. 1.0, 9:17-20 and Sched. B-2).[FN3]

****10** ComEd argues that Mr. Effron's proposed adjustment would violate the *pro forma* adjustment rule and is inconsistent with test year ratemaking. ComEd noted that Mr. Effron's proposed adjustment would be inappropriate because ComEd already has fully and completely adjusted the Depreciation Reserve for its 2005 *pro forma* additions. ComEd observes that Mr. Effron himself admitted that, for each 2005 *pro forma* plant addition, ComEd added the capital investment associated with the project, recognized a full year of depreciation reserve, and recognized a full year of Accumulated Deferred Income Taxes (‘ADIT ‘). (Effron, Tr. at 1611:11-18).

In ComEd's opinion, Mr. Effron simply replaced the 2004 depreciation reserve value with the 2005 value, reflecting one additional year of depreciation for all jurisdictional plant ***180** existing at year end 2004. According to ComEd, Mr. Effron proposed no other change to ComEd's proposed test year rate base either because of the 2005 *pro forma* plant additions, or strictly due to the passage of one year's time, as evidenced by the lack of adjustments to eight other rate base line items on his Schedule B-1. (Effron Reb., AG Ex. 3.0 Corr., Sched. B-1). ComEd avers Mr. Effron's adjustment solely rests on the effects of the passage of one more year (2005) on the depreciation reserve for this 2004 plant, the very adjustment simply due to ‘attrition‘ over time that the Commission's rules prohibit.

ComEd attests that Mr. Effron's proposed adjustment also would be one-sided and unfair. For purposes of limiting issues in this proceeding, ComEd presented a revenue requirement that took into account *pro forma* additions extending only to plant reasonably expected to be placed in service (and in service) by December 31, 2005 not, as would be permitted under Section 287.40, extending to August 31, 2006. (*E.g.*, Hill Sur., ComEd Ex. 36.0 Corr., 13:283-289). ComEd states that, as to the plant additions in 2005 included in rate base, ComEd's *pro forma* adjustments represent the full, annual rate base impact on the Depreciation Reserve and ADIT (both of which are reductions to rate base), even though these plant additions are not in-service for the full year 2005. (Hill Sur., ComEd Ex. 36.0 Corr., 12:257-261). In contrast, ComEd observed, Mr. Effron wants to reduce the rate base still further for this one item without regard to the Commission's test year and *pro forma* adjustment requirements rules.

ComEd contends that Mr. Effron's proposed adjustment is contrary to Commission decisions, given the facts of this case. ComEd notes that Mr. Effron did not cite ComEd's last rate case, Docket No. 01-0423 as supporting his proposed adjustment in this rate case. According to ComEd, in that docket, Mr. Effron testified that a downward adjustment to the entire Depreciation Reserve was appropriate where ComEd had made *pro forma* adjustments for post-test year plant additions, notwithstanding that the reserve had been adjusted for those additions. (*Commonwealth Edison Co.*, ICC Docket 01-0423 at 43 (Order March 28, 2003)). ComEd claims that the Commission rejected Mr. Effron's testimony because the proposal assumed that the entire increase in the Depreciation Reserve was due to plant additions, when in fact it was a change to the entire Depreciation Reserve for all plants, the same adjustment Mr. Effron is proposing here. (*Id.*). The Commission also rejected Mr. Effron's proposed adjustment because it would have improperly shifted the test year into the future only for the Depreciation Reserve value in rate base in that proceeding. (*Id.*).

****11** ComEd argues that none of the Commission decisions that Mr. Effron did cite supports his proposed adjustment here. (Effron Reb., AG Ex. 3.0, 11:3-12). In *Illinois Power Co.*, ICC Docket Nos. 01-0432 (Order March 28, 2002), the Commission rejected Mr. Effron's proposal to overstate the adjustment to the Depreciation Reserve. (Docket 01-0432 Order at 21). According to ComEd, in the other cases that Mr. Effron cited - *Central Illinois Light Co.*, ICC Docket 02-0837(Order Oct. 17, 2003), and *Central Illinois Public Service Co. (AmerenCIPS) and Union Electric Co. (AmerenUE)* , ICC Docket. 020798, 03-0008, 03-0009 Cons. (Order Oct. 22, 2003) - the Commission found that where historical plant in service is either declining or static, post test year *pro forma* increases in plant in service require further analysis lest, by viewing those adjustments in isolation, it appears that there should be an increase to rate base when, in fact, after netting out the effect of declining plant in service and Depreciation Reserve with the *pro forma* additions, there should be a *decrease* in rate base. ComEd states that here, by contrast, ComEd's net plant in service increased from 2003 to 2004, and that increase is greater than the amount by which the *pro forma* capital additions increase net plant (without even considering the 2003 to 2004 net increase in general and intangible plant), thereby disproving the basis for Mr. Effron's entire adjustment. ComEd Ex. 5.1 Schedules B-5 and B-6 show an increase in net distribution plant of $312,225,000 from 2003 to 2004, which is more than the increase ***181** that would be made by ComEd's *pro forma* capital additions, $312,536,000. ComEd also had an additional net plant increase from 2003 to 2004 due to increases in General Plant and Intangible Plant. (ComEd Ex. 5.1 Scheds. B-5, B-6, C-12, p. 1, l. 2; ComEd Ex. 5.2, work paper WPB-1, p. 1, ll. 13-14). ComEd further attests that at the time the rates to be set in this proceeding will be in effect (starting January 2, 2007), ComEd's net plant will increase due to the 2006 plant additions that will occur, none of which is reflected in ComEd's proposed rate base. ComEd thus opined that the Commission Orders on which Mr. Effron relied do not support, and the relevant facts directly undermine, his proposed adjustment.

AG

The AG proposes an adjustment to the Company's accumulated reserve for depreciation in order to make the *pro forma* balance consistent with the *pro forma* plant in service included in rate base, which reflects one additional year of depreciation expense on distribution and general plant. This adjustment would increase the *pro forma* balance of accumulated depreciation and amortization reserve by $311,248,000. The AG's witness Mr. Effron estimated the cost of removal on forecasted distribution plant retirements in 2005 of $46,702,000, charged against the accumulated depreciation reserve, making the net adjustment to the Company's depreciation and amortization reserve an increase of $264,002,000, and decreasing the Company's rate base by $264,002,000.

CUB-CCSAO-City

****12** CCC no longer contests this issue. In direct testimony, CCC witness McGarry originally recommended that the Company reduce its 2005 Plant Additions by $35.8 million and record this amount as a reduction to

Account 108 - Accumulated Reserve for Depreciation. CCC further recommended that ComEd reduce its estimated retirements by $32 million to reflect the reclassification of dollars from plant additions to Accumulated Reserve for Depreciation. However, ComEd correctly noted in rebuttal testimony that a transfer of dollars from Account 101 - Utility Plant in Service to Account 108 - Accumulated Reserve for Depreciation would not have any effect on ComEd's rate base as presented. Upon review of the calculation, CCC withdrew schedule MJM-5 of CUB Exhibit 2.02 and no longer contest this issue. (*See also* March 23, 2006 Tr. at 912; CCC Ex 5.01, Schedule MJM-5 (withdrawn), e-docket March 29, 2006).

Commission Analysis and Conclusion

At issue here is the AG's proposed adjustment to the accumulated reserve for depreciation in order to make the *pro forma* balance consistent with the *pro forma* plant in service included in rate base. ComEd contends that the proposal presented by the AG violates Section 287.40 and test year rate making principles. The AG's proposed adjustment does not correlate to any *pro forma* 2005 capital additions or any plant adjustment proposed by any of the parties. Instead, the AG's proposal merely takes one part of the rate base and moves it one additional year into the future. ComEd argues that the Commission rules and test year ratemaking principles prohibit such an adjustment. The Commission concurs with ComEd as to this issue. Further, the Commission finds the cases presented by the AG to be inapplicable and without merit. The Commission agrees with ComEd's assertion that the effect of the AG's proposed adjustment would be to inappropriately bring the test year into the future for accumulated depreciation. The Commission rejects the AG's proposed adjustment. Accordingly, the Depreciation and Amortization figure that corresponds to rate base approved herein is reflected in the Appendix attached to this Order.

2. GENERAL PLANT: FUNCTIONALIZATION AND AMOUNT; INTANGIBLE PLANT: FUNCTIONALIZATION AND AMOUNT

ComEd

***182 [15, 16]** ComEd describes delivering electricity to more than 3 million customers as a capital intensive business. ComEd points out that beyond distribution plant facilities (*e.g.*, substations), the electric delivery business requires ‘general‘ investments, for example, in office buildings, automated communications equipment (‘SCADA‘) that provides data used to reduce outages, and vehicles used in meter reading. ComEd asserts that it has made ‘intangible‘ capital investments as well, for example, in computer software used in the systems that provide customer information and that handle billing. (*E.g.*, Hill Dir., ComEd Ex. 5.0, 19:394- 402, 19:409-20:417, 22:459-71; ComEd Ex. 5.2 work paper WPB-1, pp. 2-12; DeCampli Dir., ComEd Ex. 4.0 Corr., 39:807-813; Hill Sur., ComEd 36.0 Corr., 23:511-519 and Sched. 7) (discussing both general plant and intangible plant assets)).

****13** According to ComEd, when the Commission first established delivery services rates for ComEd, it concluded that general plant and intangible plant presented a complex allocation question. At that time, ComEd was an integrated utility, still owning generating plants and engaged in both producing and delivering electricity. ComEd states that as there was no simple way to determine precisely how much of the general plant and intangible plant related to the delivery services business (for which rates were being set) and how much related to the separate generation or ‘production‘ business. A significant amount of the testimony in that delivery services rate case addressed this allocation question, attempting to divide general and intangible plant between ComEd's two businesses.

ComEd contends that the need for such a complex allocation has been eliminated in this proceeding, as ComEd no longer owns generating plants (having divested them on January 1, 2001) and no longer engages in the production of electricity. The general and intangible plant assets that are included in its rate base all relate to the delivery services business because ComEd has no other business. (*E.g.*, Costello Reb., ComEd Ex. 13.0 Corr., 9:173-187; Clark Dir., ComEd Ex. 1.0, 3:57-58; Lazare

Reb., Staff Ex., 17.0, 16:379-381 ('ComEd was a different utility in 2000 because it still owned generation. ComEd today is solely a transmission and distribution utility.'); Lazare, Tr. at 632: 11-17 (the last time that ComEd had significant production capital costs or production operating expenses, not including purchased power expenses, was 2001); *Id.* at 643:7-13 (ComEd is 'just a T&D utility' now)). ComEd asserts that the only allocation task is dividing its general plant and intangible plant between its Illinois distribution/customer business and its FERC-jurisdictional transmission business.

ComEd argues that the general and intangible plant assets included in its rate base were prudently acquired, that the costs incurred to acquire them were reasonable, and that the assets are used and useful exclusively in providing distribution and customer service. For example, ComEd presented the testimony of John Costello, its Executive Vice President and Chief Operating Officer, who explained the distribution and customer service functions that could not be performed without general plant and intangible plant assets. (Costello Dir., ComEd Ex. 3.0 Corr., 19:395-21:443). ComEd also presented David DeCampli, its Vice President, Asset Investment Strategy and Development, who testified that, out of the 21 largest capital additions included in rate base since ComEd's 2001 delivery services rate case, six are general plant assets and five are intangible plant assets used to provide distribution and customer service. (DeCampli Dir., ComEd Ex. 4.0 Corr., 1:10-2:41, 16:341-17:368, 37:770- 55:1154; ComEd Ex. 4.3 Corr).

In addition, ComEd witness Mr. Hill, its Director of Revenue Policy, discussed the 'direct assignment' method ComEd followed to establish the general plant and intangible plant assets being used for the distribution and customer service 'functions.' ComEd states that Mr. Hill's explanation of this 'functionalization' process addressed each individual General Plant Account and the software systems that constitute Intangible Plant. (Hill Dir., ComEd Ex. 5.0 Corr., 12:257-13:282, 18:372-22:471; ComEd Ex. 5.1, Scheds. B-1, B-2.1, B-4, B-5, and C-12: ComEd Ex. 5.2, work papers WPA-5, ***183** WPB-1, WPB-2.1b, WPB-5, and WPC-12). Mr. Hill testified that ComEd excluded from rate base the General Plant and Intangible Plant costs that support the transmission function. In addition, ComEd witness Mr. Heintz further described the direct assignment method. According to Mr. Heintz, it is the correct approach to functionalize general plant and intangible plant. (Heintz Dir., ComEd Ex. 11.0, 9:181-195, 11:238-240, 13:266-269, 14:289- 17:361).

****14** ComEd contends that Staff's and IIEC's proposals to disallow $304 million (Staff) or at least $441 million (IIEC) of ComEd's General Plant and Intangible Plant costs in rate base essentially ignored ComEd's use of direct assignment to include General and Intangible Plant in rate base. According to ComEd, neither identified any General Plant or Intangible Plant assets included in rate base that have an unreasonable cost, were not prudently acquired, or are not used and useful in providing distribution and customer service. ComEd asserts that no party contested that ComEd properly and accurately excluded the General Plant and Intangible Plant costs that support the transmission function from rate base. ComEd states that the Staff witness who reviewed the 21 largest additions to rate base, including the six General Plant assets and the five Intangible Plant assets, supported the inclusion of those assets in rate base. (Linkenback Dir., Staff Ex. 8.0, 4:42-6:121). ComEd opines that Staff and IIEC never even seriously considered the actual assets in ComEd's General Plant and Intangible Plant Accounts in proposing adjustments thereto.

As an example, ComEd argues that the Staff witness Mr. Lazare admitted that he did not specifically examine any of the General Plant and Intangible Plant Accounts (Lazare, Tr. at 643:14-644:12); that General Plant Account 397 - Communications Equipment, which includes $517,757,458 out of ComEd's $1,136,816,693 in gross General Plant before functionalization (ComEd Ex. 5.2, work paper WPB-1, p. 2), includes costs of SCADA, but that he does not know how much (Lazare, Tr. at 647:3-20); and that all but $5,815,979 of ComEd's gross $258,767,979 in Intangible Plant before functionalization are costs of six software systems, and that neither he nor any other witness has claimed that ComEd's evidence regarding how those six software systems are used is incorrect. Lazare, Tr. at 644:18- 646:3; *see also* Lazare, Tr. at 650:16-653:7 (including Staff's objection based on Staff's witness' lack of knowledge). Similarly, ComEd avers that IIEC's witness on this subject did not review substantial portions of ComEd's evidence on this subject, did not review the documents that ComEd made available in discovery on this subject, and performed only a superficial and incomplete analysis, which included no analysis of any individual General Plant and Intangible Plant Accounts and assets. (*E.g.*, Chalfant, Tr. at 1663:1-11, 1663:16 1664:3, 1665:3-14, 1666:3-1686:22, 1687:16-1688:1, 1688:8-17; ComEd Cross Exs. 10, 11 and 12).

ComEd also notes that after Staff and IIEC questioned the level of general plant or intangible plant costs included in ComEd's rate base, ComEd provided additional evidence substantiating its costs and the methodology used to determine them. According to ComEd, it pointed out multiple flaws in the arguments advanced by Staff and IIEC regarding their positions. (*E.g.*, Costello Reb., ComEd Ex. 13.0 Corr., 3:54-63, 9:173-187, 26:586-31:694; Hill Reb., ComEd Ex. 19.0 Corr., 14:280-27:554 and Scheds. 3, 4, 5, 6, 7, 8, and 9; Heintz Reb., ComEd Ex. 25.0, 5:88-97; Costello Sur., ComEd Ex. 30.0, 1:21-25, 2:38-4:81, 12:248-14:289, 22:442-23:452; Hill Sur., ComEd Ex. 36.0 Corr., 14:291-23:523 and Scheds. 5, 6, and 7).

****15** ComEd believes that Staff's proposed adjustment is based on the Commission's reduction of ComEd's general plant and intangible plant costs in the 2001 delivery services rate case by $405,161,000 (gross amount), *Commonwealth Edison Co.*, Docket 01-0423 at 41 (Order, March 28, 2003). (*E.g.*, Lazare Dir., Staff Ex. 6.0 Corr., 2:29-34, 3:61-68, *et seq*). ComEd argues, however, that such a reduction has nothing to do with the outcome in this proceeding. ComEd noted that the Commission is legally required to base its ruling exclusively on the evidence in the record of this case, and to do ***184** otherwise would be reversible error. (*E.g.* , 220 ILCS 5/10-103, 10-201(e)(iv)). ComEd notes that past Commission Orders are not legal precedents, nor are they a basis for *res judicata. (E.g.* , *United Cities Gas Co. v. Illinois Commerce Comm'n,* 163 Ill.2d 1, 22-23 (1994); *Mississippi River Fuel Corp. v. Illinois Commerce Comm'n,* 1 Ill. 2d 509, 513, 116 N.E.2d 394, 396-97 (1953)). According to ComEd, Staff's proposed adjustment is not supported by the evidence in this proceeding and it must be rejected.

It appears to ComEd that Staff now seeks to support its position based on the premise that ComEd's January 1, 2001 divestiture of its nuclear plant assets should not have substantially altered the amount of General Plant and Intangible Plant functionalized to Illinois-jurisdictional delivery services. However, when the divestiture took place, ComEd transferred the General Plant and Intangible Plant assets that supported the production function out of ComEd. As part of the divestiture and reorganization, ComEd transferred $96,684,000 of its General Plant and Intangible Plant assets to Exelon Generation and $66,749,000 of its General Plant and Intangible Plant assets to Exelon Business Services Company, a total of $163,433,000. According to ComEd, the General Plant and Intangible Plant that remained at ComEd was only the General Plant and the Intangible Plant supporting the provision of delivery services. (Hill Reb., ComEd Ex. 19.0 Corr., 19:413-21, 23:463-24:493 and Sched. 4 and 7; Hill Sur., ComEd Ex. 36.0 Corr., 14:308-15:324 and Sched. 5; Hill, Tr. at 921:7-927:2; ComEd Redirect Ex. 3). At the evidentiary hearing, ComEd witness Mr. Hill testified that the divestiture did not substantially change ComEd's functionalization of its General Plant and Intangible Plant. Instead, in Docket 01-0423, the Commission's Order, by using the general labor allocator rather than ComEd's direct assignments, created a $405,161,000 (gross amount) reduction in ComEd's rate base and thus its revenue requirement due to the divestiture that exceeded the amounts that actually supported the production function, as shown by the amounts transferred. (Hill, Tr. at 921:7-927:2; ComEd Redirect Ex. 3). Thus, ComEd avers, Staff's proposal contradicts the very ratemaking theory that Staff appears to espouse, that the divestiture should not have materially affected the amounts of General Plant and Intangible Plant that support delivery services. ComEd argues Staff's proposal materially reduces the amounts of General Plant and Intangible Plant that support delivery services by ascribing $303 million of such plant to the divested production function, rather than the correct $163,433,000 that was transferred over five years ago and thus was never in ComEd's proposed rate base in the first place.

****16** ComEd also contends that the Commission's Order in Docket 01-0423 itself rejected the position Staff is taking here: the Commission stressed that its conclusion on the subject of general plant and intangible plant was ‘for purposes of this proceeding only, and without prejudging any issues that may arise in future cases concerning the allocation of general and intangible plant using other test years.‘(*Commonwealth Edison Co.*, Docket 01-0423 at 41 (Order, March 28, 2003).*See also* Lazare, Tr. at 634:15-635:13; ComEd Cross Ex. 3).

Even the general ‘labor allocator‘ approach used by the Commission in Docket 01-0423 is inconsistent with the position Staff takes in this proceeding, ComEd argues. ComEd points to its testimony in support of its contention that, if the general labor allocator approach were applied to ComEd's General Plant and Intangible Plant additions to rate base since Docket 01-0423, then the general plant and intangible plant costs included in rate base would increase by $75,993,818. (Hill Reb., ComEd Ex. 19.0 Corr., 26:545-27:554 and Sched. 9; Hill Sur., ComEd Ex. 36.0 Corr., 16:345-51). ComEd further states that if the general labor allocator based on the 2004 test year were applied to all of ComEd's general plant and intangible plant (not just the additions since Docket 01-0423), then the general plant and intangible plant costs included in rate base would increase by $137,834,000. (Hill Sur., ComEd Ex. 36.0 Corr., 16:351-17:359 and Sched. 6).

ComEd also avers that Staff's position ***185** overlooked the support in past Commission orders for use of ‘direct assignment‘ of costs where feasible, rather than relying on the general labor allocator approach. ComEd notes the Commission's Order in *Illinois Commerce Comm'n v. Central Illinois Light Co., et al.*, Docket 99-0013 at 44 (Order, October 4, 2000), stated: ‘As a general proposition, the Commission believes that direct assignment of costs is superior to the application of general allocators if the costs are suited to direct assignment and sufficient cost data is available to make direct assignments.‘ ComEd also notes that the Commission's Order in Docket 01-0423 at 79, when discussing A&G expenses, expressly reaffirmed and quoted that language from the Order in Docket 99-0013.

ComEd states that Staff's position is inconsistent with Section 16-111(g) of the Act, 220 ILCS 5/16-111(g), and the Commission's Order in *Commonwealth Edison Co.*, Dockets 00-0369 and 00-0394 Cons. (Order, August 17, 2000). According to ComEd, in that Order, the Commission reviewed and gave advance approval for ComEd's January 1, 2001, transfer of its nuclear plant assets to Exelon Generation under Section 16-111(g), and part of ComEd's compliance with the Order was its filing of the journal entries showing the assets to be transferred, including general plant and intangible plant assets. (Hill Sur., ComEd Ex. 36.0 Corr., 15:314-19. *Commonwealth Edison Co.*, ICC Dockets 00-0369 and 00-0394 Cons. at 27, Finding (10) (Order, August 17, 2000)). ComEd opines that Staff is seeking to review and revise the asset transfer in this proceeding. ComEd argues that Section 16-111(g) prohibits any such action, providing that: ‘The Commission shall not in any subsequent proceeding or otherwise, review such a reorganization or other transaction authorized by this Section, but shall retain the authority to allocate costs as stated in Section 16-111(i).‘ ComEd states that Section 16-111(i) does not authorize Staff's position.

****17** ComEd states that in his direct testimony, IIEC witness Alan Chalfant presented only a superficial discussion of ComEd's general plant and intangible plant costs. In ComEd's opinion, Mr. Chalfant pointed to the increase from the level of such costs approved in Docket 01-0423, incorrectly claimed that ComEd had not presented any valid reason for that increase, and then constructed his proposal that the increase in such costs be limited so as to be proportional to the increase from the level of distribution plant costs approved in Docket 01-0423 to the level of distribution plant costs approved in this case out of thin air, not evidence. (Chalfant Dir., IIEC Ex. 2.0, 2:23-27, 2:35-3:43, 6:110-8:157).

According to ComEd, IIEC's position lacks merit.

ComEd states that after it had refuted IIEC's direct testimony, IIEC had offered no rebuttal testimony on this subject at all. ComEd also states that IIEC's simplistic calculations of that increase far overstated the real increase from the 2000 test year to the 2004 test year. In ComEd's opinion, its proposed general plant and intangible plant costs in rate base are properly included, and its evidence refutes the IIEC witness' claims. ComEd argues that there was no basis for Mr. Chalfant's claim that ComEd's evidence is insufficient, and that he admitted on cross-examination that his analysis and proposal were not based on any facts about ComEd's general plant and intangible plant assets. Finally, ComEd attests that that proposed limitation was not supported by the facts, there was no valid basis for making such a linkage, and that, properly calculated, the increase in General Plant was not out of line with the IIEC's witness' novel theory, in any event. (Hill Reb., ComEd Ex. 19.0 Corr., 25:506-26:526 and Sched. 8; *see also* Heintz Reb., ComEd Ex. 25.0, 5:88-97).

ComEd avers that CES offered only wholly conclusory testimony on this subject. (*See* O'Connor/Domagalski Reb., CES Ex. 5.0, 7:150-8:168). ComEd explained that CES' proposal to move some of these costs to the Supply Administration Charge (‘SAC‘) should be rejected, as ComEd opines that its general plant and intangible plant costs included in rate base belong there. ComEd states that CES did not show that any of those costs are costs of the production function. (Hill Dir., ComEd Ex. 5.0 Corr., 24:521-23; ComEd Ex. 5.2 at work paper WPC-1b; Crumrine Dir., ComEd Ex. 9.0 Corr., 46:1008-47:1013; Alongi/McInerney Dir., ***186** ComEd Ex. 10.0, 3:62-63, 15:372-16:383; ComEd Ex. 10.7; Hill Sur., ComEd Ex. 36.0 Corr., 37:832-38:855). ComEd states, however, that if Staff's proposed adjustment were adopted, then, because it was based on the functionalization determination made in Docket 01-0423, the Commission should also approve use of the SAC or some other mechanism to enable ComEd to recover fully those removed costs, including a reasonable rate of return. ComEd argues it would make the most sense to use a mechanism other than the SAC, one that applies to all retail customers, for the same reasons discussed as to its Procurement Case expenses, addressed later in this Order.

Staff

****18** Staff recommends ComEd's General & Intangible (‘G&I‘) plant for the 2004 test year be reduced by $304 million. According to Staff, ComEd should not be allowed to place 2000 test year G&I plant that was excluded by the Commission in ComEd's last delivery service rate case (Docket No. 01-0423) back into rate base for the 2004 test year.

Staff opines that ComEd's proposed increase in G&I plant is clearly unreasonable and unjustified. (Staff Ex. 6.0 Corr, p. 3) ComEd's proposal should be rejected because (1) it is an attempt to allocate costs to distribution that the Commission previously allocated to generation, (2) the overall increase in G&I plant is unexplained, and (3) all things held constant, divestiture of the generation plant, by itself, should not increase costs of G&I plant to delivery services.

According to Staff, ComEd proposes to more than double the level of G&I plant over the currently approved level. The Company proposes G&I plant of $1,079,579,000 ($840,736,000 in General plant and $238,843,000 in Intangible plant). This represents an increase of $632,988,000 (or 142%) from the $446,591,000 of G&I plant approved in the previous delivery services tariff case, Docket No. 01-0423 (*Commonwealth Edison Company, Petition for approval of delivery services tariffs and tariff revisions and of residential delivery services implementation plan and for approval of certain other amendments and additions to its rates, terms and conditions* , Ill. C.C. Docket No. 01-0423, Final Order, Appendix A, Schedule 3 (March, 28, 2003) (‘01-0423 Order ‘)). (Staff Ex. 6.0 Corr, p. 5, lines 95-99). Staff argues that more than half of the proposed increase to G&I plant, $405 million of the approximately $633 million increase, results from the Company's proposal to restore G&I plant to the distribution rate base that the Commission removed in Docket No. 01-0423. (Staff Ex. 6.0 Corr, p. 12). In Docket No. 01-0423, Staff avers, the Commission significantly reduced ComEd's proposed level of G&I plant supporting delivery services based on its determination of the appropriate allocation of G&I plant between production, transmission and distribution. (*01-0423 Order*, p. 41).

Staff argues that the G&I Plant allocated to generation in Docket No. 01-0423 should not be reallocated to distribution, because it is an attempt to allocate to delivery services rate base the very same costs that the Commission allocated to the generation function in Docket No. 01-0423 when ComEd still owned generation. (*See* 01-0423 *Order*, p. 37-38, 41). The allocation approach ComEd proposed in Docket No. 01-0423 is the same that it is proposing in this proceeding. (*See* 01-0423 *Order*, p. 34; ComEd Ex. 5.0 Corrected, p. 18) Staff attests that in Docket No. 01-0423, ComEd proposed to directly assign G&I plant costs when possible, and to use a general labor allocator when costs cannot be specifically attributed to an Illinois-jurisdictional service. In Docket No. 01-0423 the Commission rejected ComEd's proposal in favor of the general labor allocator. Applying the general labor allocator reduced gross plant by $405,160,914. (*01-0423 Order*, p. 37). According to Staff, ComEd acknowledged in response to Staff data request PL 1.15 that $405 million of its increase in G&I is attributed to what the Commission removed in Docket No. 01-0423. (Staff Ex. 17.0 Corr, p. 9).

****19** Staffs states that its proposed adjustment is based on the Company's lack of legitimate support for changing the Commission's decision to exclude certain G&I plant from ComEd's delivery***187** service rate case. Staff argues ComEd's attempt to reallocate $405 million into rate base that the Commission had assigned to production in Docket No. 01-0423 not only nullifies the Commission decision in Docket No. 01-0423, it runs counter to the Commission's continuing efforts to ensure that the production function receive a reasonable allocation of G&I plant. (Staff Ex. 6.0 Corr, p. 13; *99-0117 Order*, p. 12; *99-0129/99-0134 Order* (Illinois Power), p. 30 (Aug. 25, 1999); *99-0121 Order* (AmerenCIPS and AmerenUE), p. 21 (Aug. 25, 1999)).

Staff believes ComEd's proposal is nothing more than a collateral attack of the Commission's decision in Docket No. 01-0423.Staff argues while ComEd's proposal is a subtle form of collateral attack, collateral attacks are impermissible and ComEd's proposal must be viewed in this light. Illinois courts have held that a party to a pending action cannot initiate a new proceeding seeking relief that is or could have been the subject of another pending proceeding. (*East Side Levee and Sanitary District v. Madison County Levee and Sanitary District*, 54 Ill. 2d 442, 445, 298 N.E.2d 177, 179 (1973); *Illini Coach Co. v. Illinois Commerce Commission*, 408 Ill. 104, 110, 113 (1951)). Staff opines that if ComEd thought that excluding the $405 million was a decision in docket No. 01-0423 that it should challenge, the matter could and should have been appealed at that point pursuant to 220 ILCS 5/10-113 and 5/10-201 prescribe the procedure. The G&I plant costs established in the last rate case were approved by the Commission because they were found to be ‘just and reasonable‘ for setting rates. ComEd cannot simply undo the Commission's decision in the last rate case. ComEd has the burden of presenting evidence showing that the increase in G&I costs are attributed to actual costs, and it has not done so.

Staff also asserts that there is a lack of evidentiary support for increasing G&I plant by 142%. ComEd seeks to more than double the amount of G&I plant costs and neither Mr. Hill nor any other ComEd witness explain why such a significant increase (142%) is needed over the level accepted by the Commission in ComEd's last DST rate case, Docket No. 01-0423. (Staff Ex. 6.0 Corr, p. 5, 109-113).

Staff also argues that ComEd's divestiture of generation plant, by itself, should not increase costs of G&I plant. ComEd witness Hill states that the Company divested its generation units on January 1, 2001 and therefore since 2000 has ‘…no production plant, and, other than its purchased power expense, no significant production operation and maintenance expenses, and no significant labor assigned to production cost… .‘ (ComEd Ex. 19.0 Revised, p. 17). Thus, Staff avers, because ComEd has no production plant as of December 31, 2004, Mr. Hill contends that ‘no rationale can be made that any of ComEd's General Plant and Intangible Plant included in its 2004 test year delivery services rate base support a production functional component‘. (ComEd Ex. 19.0

Revised, p. 22). In addition, ComEd witness Costello states that '…ComEd's expenditures and books do not include any costs that can be attributed to the Production function.' (ComEd Ex. 13.0, p. 27). Staff's position is that these claims are simply not true. As stated above, $405 million of the costs ComEd proposes to functionalize to distribution were found by the Commission in Docket No. 01-0423 to be production-related. (Staff Ex. 17.0 Corr, p. 13, lines 316-320).

****20** According to Staff, in effect, ComEd's proposal would penalize ratepayers for ComEd's decision to divest generation in 2001. As ComEd acknowledged under cross, it made a business decision to divest generation. (Tr., p. 262, lines 13-14). Furthermore, ComEd witness Hill acknowledged under cross examination that rates should not go up solely because of divestiture. (Tr., p. 921, lines 7-19).

Through its proposal, Staff avers that ComEd is in effect asking delivery service ratepayers - who received no direct benefit from ComEd's decision to divest - to pay a heavy price for that decision. If, as Mr. Hill agrees, divestiture should not change the underlying cost relationships, then the conclusions of the Commission concerning 2000 test year G&I plant (*01-0423 Order*, p. 41), when ComEd owned production plant, are as meaningful and relevant today as they were in that case.

***188** Staff points out the fact that the production plant ComEd owned up until 2001 has not vanished, it has simply been shifted to an unregulated affiliate. The fact that production plant is now deregulated does not necessarily change the cost relationship with G&I plant. The production affiliate still requires expenditures on G&I plant just as when it was part of the regulated utility, and as discussed above, the Commission determined that level in Docket No. 01-0423.Thus, Staff argues, ComEd should not be allowed to roll that $405 million of G&I plant back into the distribution company's rate base.

According to Staff, its proposal is more reasonable than ComEd's proposal. Staff currently proposes that G&I plant be reduced by $304 million. Staff's proposed adjustment reverses the decision by ComEd to restore the G&I plant that existed in 2000 but was allocated to production by the Commission in Docket No. 01-0423.(*01-0423 Order*, pp. 37-38, 41). Staff avers that its adjustment would align the current delivery service tariff rate case with the decision handed down by the Commission in Docket No. 01-0423, by not allowing introduction of that same G&I plant into ComEd's delivery services rate base.

Staff states that its proposed adjustment pertains only to the 2000 test year G&I plant the Commission excluded from rate base in Docket No. 01-0423.Staff has not extended its analysis to plant additions for 2001 and beyond to determine whether they are consistent with the *01-0423 Order*. (Staff Ex.17.0 Corr, p. 14).

According to Staff, the basis for its proposed adjustment of G&I plant comes from ComEd. In discovery, ComEd indicated that the Commission's decision in Docket No. 01-0423'reduced ComEd's proposed test year jurisdictional general and intangible gross plant by $405 million'. ComEd then went on to note that, '[T]herefore, all other things equal, ComEd's starting point (that is, the 2000 test year used in Docket 01-0423) results in a $405 million increase.' (Staff Ex. 17.0 Corr, pp. 8-9).

Staff, however, amends its original $405 million adjustment to $304 million, in response to a valid issue raised by ComEd witness Mr. Hill concerning the calculation of Staff's proposed $405 million adjustment. Mr. Hill argues that the amount is overstated because it fails to properly account for General plant retirements between 2000 and the 2004 test year. He indicates that approximately 25% of 2000 test year General plant was retired before the end of the 2004 test year, and these retirements are not reflected in the proposed $405 million adjustment. (ComEd Ex. 19.0 Revised, pp. 20-21). Staff found this argument to be reasonable. Consequently, Staff reduced its originally proposed adjustment of $405 million by approximately 25% to $304 million. (Staff Ex.17.0 Corr, p. 14).

****21** According to Staff, in responding to Staff's proposal, Company witness Hill demonstrates a fundamental misunderstanding of Staff's proposal. He suggests that Staff has introduced a labor allocator in this proceeding as a foundation for functionalizing G&I plant. (ComEd Ex. 29.0, p. 13). That is not the case. Staff attests that it has not introduced a new allocator for G&I Plant. Rather, Staff simply seeks to be consistent with and maintain the Commission's decision in Docket No. 01-0423 with respect to current G&I plant that existed at that time. According to Staff, it is true that in Docket 01-0423 the Commission applied a general labor allocator to G&I plant. The application of the general labor allocator in that case resulted in the removal of $405 million from distribution rate base and allocated it to production. (Staff Ex. 17.0 Corr, pp. 2-3). Staff's proposed adjustment seeks to prevent ComEd from undermining that decision by restoring to the rate base for delivery services the G&I plant that the Commission had excluded in Docket No. 01-0423.

In its reply brief, Staff provided further arguments in support of its contention that the Commission should remove from rate base an amount representing what was excluded as being allocated to the production function in Docket No. 01-0423.Staff emphasizes that ComEd may have explained how it uses its plant for delivery services (ComEd Init. Br., pp. 45-46), but it has not specifically addressed how the $405 million that was denied in the previous ***189** delivery services case is reallocated in G&I plant and is used and useful. Because of this deficiency, Staff recommends that $304 million be removed from rate base.

Staff contends that ComEd overbroadly interprets the Commission's ruling in Docket No. 01-0423.According to ComEd, the Commission stressed that its conclusion for G&I plant in Docket 01-0423 was:

For purposes of this proceeding only, and without prejudging any issues that may arise in future cases concerning the allocation of general and intangible plant using other test years…

(ComEd Init. Br., p. 47). Staff contends that ComEd is overextending the application of this statement from the *01-0423 Order*. Staff argues that this statement was intended to address the method of allocating costs, and the issue of whether to use direct assignment or a general allocator. In Docket No. 01-0423, ComEd proposed the use of a direct allocator (*01-0423 Order* , pp. 39-40), while Staff proposed the use of a general labor allocator (*id*, pp. 34-38). According to Staff, this statement was not intended to foreclose Staff from understanding how the divestiture of generation in 2001 impacts the 2004 test year in this case.

In its Reply Brief, Staff also responded to ComEd's argument related to the general labor allocator. The Company argues that Staff's position also overlooks the support in the past Commission orders for use of ‘direct assignment‘ of costs where feasible, rather than relying on the general labor allocator approach.‘ (ComEd Init. Br., p. 48). Staff responds that ComEd has ignored what the Commission had to say specifically about the application of direct assignment of G&I plant:

****22** The Commission disagrees with Edison's direct assignment approach. The very nature of these costs suggests they are not amenable to direct assignment.

(99-0013 Order, p 11). Staff then asserts that this statement clearly indicates the Commission's position on this matter - that the Commission does not consider direct assignment appropriate for G&I plant.

Staff also relies upon the Commission's decision in Docket No. 01-0432 to support the use of a general labor allocator instead of direct assignment. According to Staff, ComEd is similar to the utility in Docket No. 01-0432, since they both divested themselves of generation and then attempted to allocate costs to G&I plant that had been attributed to generation in previous delivery services rate cases (Docket Nos. 990120 and 99-0134). Since the issues in those cases were nearly identical, Staff encourages the Commission to rule in a manner consistent with those dockets.

Staff also responds to ComEd's contention that Staff's position is also inconsistent with Section 16-111(g) of the PUA and the Commission's order in Docket Nos. 00-0369 and 00-0394 (Cons.) [FN4] in which the Commission approved ComEd's transfer of nuclear plant assets to Exelon Generation and presented ‘journal entries showing the assets to be transferred included general and intangible plants.‘ (ComEd Init. Br., pp. 48-49). According to Staff, ComEd argues that the Commission gave ComEd approval in advance to decide what G&I assets may be transferred to distribution and included in the revenue requirement. Staff strongly disagrees with this legal interpretation, and so did the Commission in Docket No. 01-0432.In that docket, the Commission addressed the same issue, and determined that its decision regarding divestiture under Section 16-111(g) does not predetermine how G&I assets may be transferred to distribution and included in rate base. Staff asserts that the Commission's approval of the transfers does not remove ComEd's burden of proof obligation under 200 ILCS 5/9-201(c).

In sum, Staff argues that the Commission should approve Staff's proposed adjustment of $304 million in G&I plant as a reasonable alternative to the massive and unsupported increase proposed by ComEd.

IIEC

***190** IIEC says ComEd seeks to reflect G&I Plant of $496.4 million in its rates. This represents a 222.2% increase over the $223.4 million of G&I Plant approved in the Company's last delivery service rate case, Docket No. 01-0423.In this case IIEC recommends the Commission approve a level of G&I Plant equal to the percent increase in the related net distribution plant approved for ComEd. Assuming ComEd's original requested level of distribution plant, the level of G&I Plant approved by the Commission in this case would be limited to $278.1 million.

IIEC argues its proposal is appropriate for several reasons. First, the magnitude of the requested increase in G&I Plant is not reasonable. In describing methods for allocating G&I plant, ComEd witnesses have testified that G&I Plant can house administrative and general-type activities such as administration of employee pensions and benefit plans and employee training. According to IIEC, these witnesses have testified that much of this type of plant seems to be directly involved in supporting other plant investment. IIEC says ComEd witnesses have also testified that utility plant accounts representing equipment, tools and stores seem, intuitively, to be related to the amounts of production, transmission and distribution plant owned by the utility. IIEC states that under such circumstances, it is hard to comprehend why G&I Plant would increase by 222% while the cost of the Company's distribution plant has increased by only 24.5% and the Company's O&M expenses have decreased by 12.5%. Given the relationship between the level of distribution plant and O&M expenses to the level of G&I Plant, IIEC suggests it is not reasonable that ComEd's G&I Plant would increase by 222.2% over levels approved in the last case.

****23** Second, IIEC argues while ComEd has explained the content of each of the affected G&I Plant accounts, it has not explained how or why G&I Plant has increased by 222.2% over levels approved in the last case. Therefore, according to IIEC, ComEd's proposed level of G&I Plant should not be approved in this case. Instead, the appropriate level of G&I Plant in this case should be based on the percentage increase in distribution plant authorized in this case as recommended by IIEC.

CES

CES argues that ComEd has failed to justify the restoration of G&I plant category that the Commission rejected for inclusion in the delivery service rate base in ICC Docket No. 99-0177, in accordance with past Commission practice. (*See id.*)According to the Coalition, the G&I plant in question previously had been functionalized as related to supply; ComEd now, without sufficient explanation, seeks to refunctionalize the plant as delivery-related. (*See id.*)CES endorses Staff's recommendation of a downward adjustment of $405 million in G&I plant that was allocated to delivery services. (*See* Staff Ex. 6.0 at 5-15.)

Commission Analysis and Conclusion

At issue here is Staff and IIEC's proposal to disallow $304 million or at least $441 million respectively, of ComEd's General and Intangible Plant costs in rate base. ComEd's primary argument in opposition to these proposed adjustments is that these costs were reasonably incurred and that neither party has presented any evidence to the contrary. In order for the Commission to approve such costs the Commission must find that the costs were prudent and used and useful. The Commission however, was not provided with any evidence by Staff nor the IIEC to support their proposed adjustments. While Staff highlights the fact that in ComEd's last delivery services rate case the Commission found a reduction to general and intangible plant costs to be appropriate that is not a proper basis upon which the Commission should determine costs in this rate case. The Commission is required to look thoroughly at each docket on a case by case basis. The record established here by ComEd is supported by convincing evidence that the costs associated with general and intangible plant assets are reasonable.

Further, the Commission agrees with ComEd that the use of 'direct assignment' of costs is the preferred approach over the general labor ***191** allocator approach. Because determining such costs is possible, the Commission is in agreement with ComEd that direct assignment be used in this case. Additionally, the Commission points out that the record evidence supports the fact that were the general labor allocator approach to be used in this case, general and intangible plant costs in rate base would in fact increase.

Moreover, the Commission finds 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.

****24** Similarly, the Commission finds that the record does not support the proposal by CES to reallocate some of the general and intangible plant to the SAC. CES never established that these costs are production costs. Accordingly, the Commission finds that ComEd's proposed general and intangible costs are appropriate.

3. PENSION ASSET

ComEd

[17, 18] ComEd states that a pension asset of $853.9 million (gross amount) should be included in its rate base. (Hill Dir., ComEd Ex. 5.0 Corr., Sched. B-1, p. 1). ComEd states that this asset resulted in large part from an $803 million contribution of equity that Exelon made to ComEd in March 2005 to enable ComEd to 'fully fund' its portion of the Exelon pension plan. (Mitchell Dir., Com Ed Ex. 7.0, 8:160-62; Mitchell Reb., ComEd Ex. 20.0, 16:336- 20:424). ComEd contributed the $803 million equity infusion to fund its portion of the Exelon pension plan. (Mitchell Dir., ComEd Ex. 7.0, 8:160-62; 8:170-9:173). ComEd notes that Exelon obtained the funds for the $803 million equity infusion by issuing debt and obtaining tax benefits from the contribution. (Mitchell Dir., ComEd Ex. 7.0, 8:170-9:173). ComEd argues that without the equity infusion from Exelon, ComEd would have had to issue additional debt itself, which would likely have resulted in a downgraded credit rating. (Mitchell Reb., Com Ed Ex. 20.0, 17:347-57).

ComEd attests that the $803 million pension contribution by ComEd must be included as an asset in rate base to allow Exelon shareholders and bondholders who financed the pension funding to recover their costs. (Houtsma, Tr. at 521:13-19). ComEd also states that because the contribution will generate additional pension trust fund earnings, the contribution also decreases annual jurisdictional pension expense by approximately $30 million, which has been consistently reflected in ComEd's proposed revenue requirement. (Houtsma, Tr. at 469:16-22; Mitchell Dir., ComEd Ex 7.0, 9:187-89).

According to ComEd, the $803 million contribution created a pension asset on ComEd's books for at least two reasons: (1) from an accounting point of view, the pension asset represents contributions that relate to obligations that have not yet been recognized in ComEd's financial statements, but will be in the future; and (2) from a regulatory point of view, the pension asset represents funds contributed solely by shareholders to satisfy future pension obligations in an amount above and beyond what has previously been collected from customers through rates, and thus by including the asset in rate base, ComEd is asking for a return on these shareholder supplied funds that have been invested prior to collection of these amounts from customers. (Houtsma Tr. at

468: 12-17, 469:5-8.*See also* Mitchell Dir., ComEd Ex. 7.0, 10:202-09). ComEd avers that the regulatory obligation to provide shareholders with such a return is unaffected by whether the corresponding pension liabilities remain, as they now are, on Exelon's books, or whether they instead had been recorded on ComEd's books. (Houtsma Reb., ComEd Ex. 18.0 Corr., 16:344-17:366; Heintz Reb., ComEd Ex. 25.0, 26:523-31).

****25** ComEd opines that the decision to fund the plan was prudent and reasonable. ComEd presented a comparison of the funding status of the pension plan (in which ComEd participates) before and after the contribution to the funding ***192** status of large pension plans of other employers. ComEd states that prior to the $803 million contribution, the 2004 funding level of the plan was at 72% compared to an average of 92% for other employers with large pension plans, while after the contribution, it was more in line with that of those other companies and ComEd's own goals for itself. (Mitchell Sur., ComEd Ex. 37.0 2nd Corr., at 26:528-28:540). ComEd avers that the $803 million contribution was part of a larger effort by Exelon to fund its pension plan for all employees. ComEd states that most of Exelon's employees (including all ComEd employees) participate in a corporate-wide pension plan, and Exelon announced that it would make a $2 billion contribution to its pension plan because it was the right thing to do, and Exelon had the financial strength and resources to do it. (Mitchell Dir., ComEd Ex. 7.0, 8:164-68).

ComEd states that in recent history major corporations had ran into trouble after funding their pension plans at minimum levels and then finding themselves, for whatever reason, in financial distress and unable to meet their pension commitments. (Tierney Reb., ComEd Ex. 22.0, 12:255-13:273). ComEd opines that employees are keenly aware of troubles experienced by companies that have not adequately funded pension plans and now have a heightened awareness of funded status. (Mitchell Reb., ComEd Ex. 20.0, 23:478-89). More generally, ComEd argues that perverse financial incentives would be created by adopting adjustments that would encourage the utility to fund only the minimum requirements for a pension plan and in fact would deny it cost recovery when it prudently funded more than that level. (Tierney Reb., ComEd Ex. 22.0, 12:246-49; Mitchell Reb., ComEd Ex. 20.0, 23:489-95).

ComEd argues that the Commission should approve inclusion of the pension asset in rate base, and provide ratepayers with the corresponding benefit of the approximately $30 million in reduced annual pension expense which that asset makes possible, because it is the right thing to do, and is good regulatory policy. ComEd attests that unless the pension asset is included in rate base, shareholders will not receive a return on the funds that they have invested in the pension plan prior to collection of these amounts from customers, which would be unfair and confiscatory. Moreover, ComEd states, without inclusion in rates of both the pension asset and the lower pension expenses made possible by the contribution that created that asset, ComEd rates would not appropriately reflect the cost to provide service to customers. (Tierney Sur., ComEd Ex. 39.0, 4:82-5:94).

According to ComEd, no party claimed that fully funding the pension plan was imprudent or unreasonable. In ComEd's opinion, the claims that other parties did make regarding pension asset and pension expense should be rejected.

Pension Asset

****26** With respect to the claim that no pension asset exists at all, ComEd argues that such claim is incorrect on multiple levels. ComEd noted that although a pension asset can arise from overfunding of a plan, as Staff witness Ms. Ebrey asserts, such an asset can arise in other ways, too, including: (1) where a trust fund that is used to satisfy the future obligations has generated better-than-expected asset returns, so that the available funds in the trust fund are greater than the existing obligations (not applicable here); and (2) as here, where the pension asset represents funds that have been contributed to a pension fund by shareholders and bondholders to satisfy future pension obligations in an amount above and beyond what has previously been collected from customers through rates. (Houtsma, Tr. at 471:4-11, 468:13-17).

It appears to ComEd that Ms. Ebrey was further mistaken in her belief that the asset on ComEd's books was created by accounting entries only. (Ebrey Dir., Staff Ex. 2.0, 6:103- 04). ComEd states that for accounting purposes, it is correct that if a pension liability were recorded (or pushed down) on ComEd's books, rather than Exelon's. ComEd's pension assets and liabilities would offset in amount and ComEd would no longer have a net pension asset for accounting purposes. However, *for ratemaking purposes* it would not be appropriate***193** to reduce rate base by the amount of the pushed down pension liability. ComEd avers that the pension asset would not be netted with the liability, and thus the asset would remain for ratemaking purposes, because the liability had not been recovered through customer rates and as such should not be deducted from rate base. (Houtsma Sur., ComEd Ex. 35.0, 24:531-35).

It appears to ComEd that several parties - particularly BOMA - are under the impression that because, when the $803 million contribution was made (March 31, 2005), the plan was fully funded, ComEd's pension obligation was ‘eliminated‘. (Houtsma, Tr. at 494:4-12). ComEd states that this theory is incorrect for much the same reasons as explained above, *i.e.*, because the pension contribution was made with funds supplied by shareholders and bondholders, it would continue to exist, and be a valid addition to rate base, regardless of whether the plan was, at the time of the contribution, fully funded, and regardless of whether some of the pension obligations are on Exelon's books but not on ComEd's books. (Houtsma, Tr. at 495: 1-4).

ComEd opines that Ms. Ebrey also erred in suggesting that the pension asset is not real based on her observation that the pension asset, and the capital contribution made by Exelon to provide ComEd with the cash to fund the pension contribution, both ‘disappear‘ in the financial consolidation process and do not appear on Exelon's books. (Ebrey Reb., Staff Ex. 13.0, 6:107-7:123). ComEd states that this observation is not relevant, as the effects of virtually all intercompany transactions are eliminated upon consolidation of Exelon's financial statements, but such elimination does not relieve ComEd of the obligation associated with those transactions. As an example, ComEd states that it has a payable to BSC at the end of any month related to the services it receives from BSC, for which BSC records a corresponding receivable from ComEd. Although when Exelon's financial statements are consolidated, the ComEd payable and the BSC receivable are offset against each other, and Exelon does not report either a receivable or payable, ComEd's obligation does not disappear or cease to exist. It is simply offset, for financial reporting purposes, by corresponding items on Exelon's financial statements. Thus, as ComEd states, the ‘disappearance‘ of the pension asset in the financial consolidation process is simply the result of required consolidation accounting practices under GAAP; it does not make the pension asset, or the $803 million contribution, any less real. (Houtsma Sur., Com Ed Ex. 35.0, 24:536- 25:556).

****27** With respect to Ms. Ebrey's second rationale for disallowing the pension asset - that such asset does not represent funds within ComEd's disposition and in which it has an interest (Ebrey Dir., Staff Ex. 2.0, 9:169-83) - ComEd argues that, under federal law, amounts contributed to the pension trust must be used exclusively to provide pension benefits. (Mitchell Reb., ComEd Ex. 20.0, 24:508-11). ComEd argues that penalizing a utility by not allowing cost recovery of its pension funds because these funds are not ‘funds within the Company's disposition‘ is inconsistent with the intent of direct contribution pension plans as well of the expectations of the workforce benefited by them. (Tierney Reb., ComEd Ex. 22.0, 14:290-300). According to ComEd, the Commission has consistently provided recovery to utilities of employee pension benefits, without regard to the fact that these benefits are provided through contributions to pension trust funds that, by law, cannot be accessed for general corporate purposes. (Mitchell Reb., ComEd Ex. 20.0, 24:511-14). Furthermore, ComEd avers, the pension trust funds generate investment income that reduces the amount of pension expense that is included in cost of service, and thus customers receive the benefit from these trust funds even thought they are not available for other corporate purposes.

In ComEd's opinion, Ms. Ebrey's third reason for opposing the inclusion of the pension asset in ComEd's rate base - namely, the purportedly ‘discretionary nature of the pension contribution‘ (Ebrey Reb., Staff Ex. 13.0, 5:84-85, 8:147-59; Ebrey Dir., Staff Ex. 2.0, at 9:184-11:122) - is incorrect, as well. ComEd states, as Ms. Ebrey admitted (Tr. 1891:9-17), it has never been the position of the Commission ***194** that a criterion for including an asset in rate base is that its creation was not discretionary. Rather, ComEd states, as long as the asset is used and useful and acquired at a reasonable and prudent cost, that asset goes into rate base. Ebrey, Tr. at 1891:18-22. According to ComEd, no party has challenged that the contribution to fully fund the pension obligation was reasonable and prudent.

ComEd avers that Ms. Ebrey's argument is that shareholders should not be compensated for actions by ComEd and Exelon that go beyond the minimum pension funding requirement in the law. The effect, ComEd expert Ms. Tierney testified, would be to discourage use of best practices with respect to pension funding. (Tierney Reb., ComEd Ex. 22.0, 11:223-28). ComEd further attests that ultimately ComEd has a legal obligation to fund its pension obligations to its employees. Thus, to say that its decision to fund its pension obligations is ‘voluntary‘ does not properly characterize the nature of the payment and the obligation - pension contributions would have eventually been required and would have been even higher. ComEd adds that by making the payments earlier than legally required, its pension expense will be reduced and its employees and retirees in Illinois are protected against the loss of their hard-earned pension benefits. (Mitchell Reb., ComEd Ex. 20.0, 25: 527-34).

****28** Further, according to ComEd, Staff's position fails to take into account the impact on workers of discouraging a utility from fully funding the pension plans on which its employees' retirement benefits depend. ComEd opines that employees consider its complete compensation package when deciding whether to work for or continue working for ComEd, and that a pension is a major part of that package and, thus, is a major part of attracting and retaining employees who have the experience and expertise to provide reliable service. ComEd states that employees are well aware of troubles experienced recently by other companies that have not adequately funded pension plans and now have a heightened awareness of funded status. (Mitchell Reb., ComEd Ex. 20.0, 23: 478-89).

ComEd avers that Ms. Ebrey's final argument for excluding the pension asset - that the customer impact of including that asset outweighs the benefit of the lower pension expense that results from the contribution, and therefore that the contribution is detrimental to customers and should not be included in rate base (Ebrey Reb., Staff Ex. 13.0, 9:157-10:192) - is also incorrect. According to ComEd an expenditure should not be excluded from cost of service solely because its inclusion would increase rates. ComEd states that virtually all expenditures have the effect of increasing rates, but if they are reasonably and prudently incurred costs they should be reflected in the rate setting process. ComEd argues that in prior years, customers have received the benefit of substantial rate base deductions due to unfunded pension liabilities. As an example, ComEd cites the last rate case, where the rate benefit of the unfunded pension liability deducted from the rate base more than offset the pension expense. (Houtsma Sur., ComEd Ex. 35.0, 25:561-67). Here, ComEd opines, funding the pension obligation now was reasonable and prudent. Therefore, ComEd believes that shareholders and bondholders should be compensated for providing the funds that made the contribution possible. Finally, as discussed under the ‘Pension Expense‘ subsection, *infra*, ComEd argues that Ms. Ebrey's proposal for asymmetrical treatment of the pension asset and pension expense is not consistent with or supported by the Commission Orders she cites.

The AG, at the briefing stage, recommended that the Commission adopt Ms. Ebrey's proposal to remove the pension asset from rate base and to reflect the reduction in pension expense resulting from the contribution ‘where consistent with Commission precedent.‘ According to ComEd, it is not consistent with past Commission Orders, however.

The AG also argues, alternatively, that if the Commission elects to allow a return on the pension contribution, ComEd should only be allowed to recover the cost of debt financing for the contributions, which the AG determined is $27 million. ComEd attests that this alternative, fall-back proposal by AG witness Mr. Effron to remove the pension asset from rate base, but to ***195** add to jurisdictional operating expense approximately $27 million for the cost of debt financing for the contribution (Effron Dir., AG Ex. 1.0, 12:15-14:10), though seeming at first blush to be more reasonable than Staff's asymmetrical proposal, should also be rejected. ComEd argues that its contribution to its pension was not funded by a debt issuance at ComEd. Instead, ComEd received an equity contribution from Exelon for a valid business purpose. ComEd avers that if the pension obligation had been funded by ComEd with debt, it is likely ComEd's credit would have been downgraded. (Mitchell Reb., ComEd Ex. 20.0, 17:347-57). ComEd states that maintaining acceptable credit ratings is important, and a failure to do so can adversely affect access to capital and the cost of capital. ComEd further states that as it is entering into a period of competitive procurement of power beginning in January 2007, there is even further justification for maintaining strong credit ratings to enable ComEd to obtain commercially reasonable terms on supplier contracts. (Mitchell Reb., ComEd Ex. 20.0, 20:415-24). ComEd argues that the $803 million is equity to ComEd and should be treated as such, and the costs ComEd recovers should match the return afforded for that source of capital. (Mitchell Reb., ComEd Ex. 20.0, 18:378- 19:390).

****29** In addition, ComEd argues that the AG's proposal to impute Exelon's debt cost to ComEd violates both Section 16-111(i) and Section 9-230 of the Act. Section 16-111(i) states, in relevant part, that ‘Subsequent to the mandatory transition period, the Commission, in any proceeding to establish rates and charges for tariffed services offered by an electric utility, shall consider only (1) the then current or projected revenues, costs, investments and cost of capital directly or indirectly associates with the provision of such tariffed services; …and shall not consider any other revenues, costs, investments or cost of capital of either the electric utility or of any affiliate of the electric utility that are not associated with the provision of tariffed services.‘ (220 ILCS 5/16-111(i)). Section 9-230 provides that ‘In determining a reasonable rate of return upon investment for any public utility in any proceeding to establish rates or charges, the Commission shall not include any (i) incremental risk, (ii) increased cost of capital, or (iii) after May 31, 2003, revenue or expense attributed to telephone directory operations, which is the direct or indirect result of the public utility's affiliation with unregulated or non-utility companies.‘ (220 ILCS 5/9-230). ComEd states that, taken together, these provisions establish that rates for tariffed services must be determined only by the reviewing utility's costs and risks, not the costs and risks of an affiliate. Exelon is an affiliate of ComEd, and it is Exelon, not ComEd, which incurred the debt cost (and associated risk) to fund not only the contribution to ComEd, but contributions to other Exelon affiliates as well. The dollars which Exelon obtained through the issuance of debt were an equity contribution to ComEd; ComEd issued no debt, and could not do so without jeopardizing its credit ratings. According to ComEd, the AG's proposal to impute Exelon's debt cost to ComEd is in plain violation of the Act.

Pension Expense

ComEd argues that Staff's proposal to set the pension expense level at $11.7 million, while simultaneously seeking to disallow from rate base the very pension asset that reduced expense to that level, is fundamentally unfair and at odds with longstanding and widely recognized ratemaking principles that treat costs and benefits consistently. (Houtsma Sur., ComEd Ex. 35.0, 28:618-19). ComEd maintains that the $11.7 million expense level results directly from the inclusion of the $803 million pension obligation by fully funding the pension obligation, ComEd reduced its 2005 pension expense by $30.2 million, from $41.9 million to $11.7 million. (Houtsma Reb., ComEd Ex. 18.0 Corr., 17:371-72, 18:382-88.; Mitchell Reb., ComEd Ex. 20.0, 25:539-40).

According to ComEd, Staff witness Ms. Ebrey agreed that ‘all else equal‘, the net change in test year pension expense of the contribution was a $30 million reduction. Yet, she failed to abandon her argument that if the contribution***196** had not been made, the revenue requirement would only have been $8.6 million higher. (Ebrey, Tr. at 1888:113.; Ebrey Reb., Staff Ex. 13.0, 9:180-10:192). ComEd states that position is plainly wrong, the $8.6 million figure was simply the difference between the 2004 pension expense of $33.3 million and the $41.9 million that the 2005 pension expense would have been without the contribution - not what the change in pension expense from the reduced level of expense that ComEd proposed in its revenue requirement in light of the contribution would have been if the contribution had not been made. (Houtsma Sur., ComEd Ex. 35.0, 26:571-27:593; ComEd Ex. 35.3). Instead, ComEd attests, the $8.6 million is the net increase in pension expense in 2005 due to factors other than the pension contribution (*e.g.*, lower than expected 2004 asset returns), which are unrelated to and would have occurred regardless of the pension contribution.

****30** ComEd also maintains that Ms. Ebrey's treatment of pension expense is not consistent with prior Commission orders holding that pension expense should be updated based on the latest actuarial valuation. (Ebrey Dir., Staff Ex. 2.0, 13:262-68; Ebrey Reb., Staff Ex. 13.0, 13:262-14:268). ComEd states that it agreed that an updated actuarial analysis can provide an appropriate basis for a known and measurable test year adjustment and test year data was updated to reflect the latest actuarial analysis as of the filing. (Hill Dir., ComEd Ex. 5.0 Corr., 36:777-80; Houtsma Sur., ComEd Ex. 35.0, 28:628-631). ComEd argues, however, that the problem with Ms. Ebrey's approach was its unjustifiable asymmetry, in that she sought to take advantage of a lower pension expense, whether updated or not updated, made possible only by the pension asset she simultaneously sought to disallow.

In ComEd's opinion, Ms. Ebrey was equally incorrect in asserting that her asymmetrical treatment of the pension contribution and pension expense was consistent with prior commission orders. (Ebrey Dir., Staff Ex. 2.0, 14:272-80). ComEd noted that although in the recent Nicor Gas rate case cited by Ms. Ebrey (Docket 040779), the Commission disallowed the requested pension asset from rate base, while allowing a pension credit to reduce operating expense, the circumstances resulting in the pension asset in that case were quite different from the circumstances here. According to ComEd, in the Nicor Gas proceeding, the Commission determined that the pension asset should not be included in rate base because it arose from ratepayer supplied funds. Here, by contrast, it is undisputed that ComEd's pension asset arose solely and exclusively from shareholder-supplied funds, and the liability that was funded has not previously been recognized in cost of service. (Houtsma Reb., ComEd Ex. 18.0 Corr., 19:407-19). ComEd distinguishes the Commission's decision in the GTE case cited by Ms. Ebrey (*GTE North Inc.* , ICC Docket 93-0301/94-0041 (cons.), 1994 Ill. PUC Lexis 436 (Order Oct. 11, 1994)) on similar grounds. There, as in the Nicor Gas case, the pension asset was created through rates, which is not the case here. ComEd avers that the circumstance that led the Commission to exclude the pension asset in both the Nicor and GTE orders is simply not present in this case. ComEd argues that in complete contrast to either of those cases cited by Staff, ComEd's pension asset is a result of shareholder - not ratepayer - supplied funds. ComEd maintains that at the hearings, Staff effectively conceded that neither of these cases applied here, when at the close of his recross of Ms. Houtsma on the pension asset issue, counsel for Staff asked, ‘That's the point of my question. This is a case of first impression, isn't it?‘, to which Ms. Houtsma replied, ‘I'm not aware of a similar situation.‘ (Houtsma, Tr. at 524:22-525:2).

ComEd argues that Staff's position here was inconsistent with Staff's proposed customer deposits and budget payment plan balances adjustments to rate base. According to ComEd, Staff's theory there is that customers are acting as a source of capital that reduces ComEd's costs. Here, shareholders are acting as an analogous source of capital and even Staff witness Ms. Ebrey agrees that in such a circumstance shareholders are entitled to a return.

****31** In summary, ComEd states that the Commission should approve the pension asset, in ***197** which event the appropriate pension expense is $11.9 million. ComEd further states, however, that if, despite substantial record support, the Commission decided nonetheless not to include the pension asset in the rate base, the jurisdictional pension expense should be $41.9 million. (Houtsma Sur., ComEd Ex. 35.0, 28: 626-29: 635).

In ComEd's opinion, Mr. Effron's proposed adjustment to pension expense to recognize a full year's effect of the pension contribution (Effron Dir., AG Ex. 1.0, 23:10-24:2) should be rejected. ComEd avers that the pension contribution was made in March 2005, and the increase in investment returns due to that contribution will reduce pension expense by $30.2 million in 2005, which has been reflected in test year pension expense. ComEd states that it reflected the full and complete *pro forma* adjustment, including the 2005 expense level based on the most recent actuarial study. (*E.g.*, Hill Dir., ComEd Ex. 5.0 Corr., 36:777-80). ComEd also maintains that Mr. Effron's suggested full-year's effect will not be realized until 2006. (*Id.*, at 23:18-19). ComEd further states that many factors affect pension expense and are factored into an actuarial analysis, including discount rates, demographic experience, asset returns and other normal actuarial changes. ComEd avers that all of these factors will impact 2006 pension expense, and thus Mr. Effron's proposal to slice out just one of these factors to reflect updated 2006 levels is inappropriate and one-sided. (Hill Reb., ComEd Ex 19.0 Corr., 39:814-29).

Staff

Staff witness Ms. Ebrey recommends that the Company's *pro forma* adjustment to include a ‘pension asset‘ in its proposed rate base be reversed. (Staff Ex. 2.0, pp. 3-13). Staff presented three main bases for its proposed reversal of ComEd's adjustment. (*Id.*, pp. 6-7).

First, Ms. Ebrey argues that the pension contribution allocated to ComEd should not be considered separately from the offsetting pension liability attributed to ComEd that gave rise to the contribution. (*Id.*, p. 7). She states that as defined by the Statement of Financial Accounting Standards No. 87, a pension asset is recognized if net periodic pension cost is less than amounts the employer has contributed to the plan. (*Id.*, p. 4). Ms. Ebrey testified that when the pension liability and the pension asset are taken together, no pension asset exists because the Accumulated Pension Obligation is offset by the pension asset. As a result, the pension plan is fully-funded and not over funded. (*Id.*). Further, Ms. Ebrey testified that although Exelon Corporation stated that the pension plan is fully funded, leaving neither a pension asset nor liability on its books, that fact has not been reconciled to the decision to only reflect an asset on ComEd's books without the offsetting liability. (Staff Ex. 13.0, p. 6).

Ms. Ebrey also testified that the Company's reporting to the Securities and Exchange Commission (such as in Form 10-Q) does not support the existence of this pension asset on a consolidated basis. (Staff Ex. 2.0, pp. 6-8). Ms. Ebrey testified that the absence of a pension asset on Exelon Corporation's March 31, 2005 Form 10-Q consolidated balance sheet indicates that the pension assets for ComEd, PECO, and Exelon Generation were eliminated through the consolidation process as intercompany transactions. (*Id.*, p. 6).

****32** Second, Ms. Ebrey testified that the ‘pension asset‘ adjustment should be reversed because the pension trust to which the contribution was made does not represent funds within the Company's disposition. (Staff Ex. 2.0, p. 9). She stated that ComEd should not be able to earn a return on something in which it has no interest. (*Id.*).

Third, Ms. Ebrey testified that the ‘pension asset‘ should be reversed because the discretionary nature of the timing of the pension contribution does not support including some portion of that asset in ComEd's rate base. (Staff Ex. 2.0, pp. 9-12; Staff Ex. 13.0, pp. 8-9). According to Ms. Ebrey, at no point does ComEd claim that the funding made in 2005 was pursuant to a legal requirement of the plan or that it was necessary for it to be able to provide safe and reliable service to its customers. (Staff Ex. 2.0, p. 11; Staff Ex. 13.0, p. 8). Further,***198** Ms. Ebrey states that ComEd's proposed ratemaking treatment of its discretionary contribution is detrimental to its ratepayers because it increases the revenue requirement by $27.9 million annually. (Staff Ex. 13.0, pp. 9-10). She testified that the only impact on the revenue requirement, absent the contribution, would have been an increase to pension expense of $8.6 million rather than the adjustments proposed by the Company which increase the revenue requirement by a total of $27.9 million. (Staff Ex. 13.0, p. 10).

Staff maintains that the Company will recover the costs associated with its pension plan under Staff's proposal; namely, it will recover the periodic costs of the pension plan as determined by the Company's actuary through pension expense included in the revenue requirement. (Staff Ex. 2.0, pp. 13-14; Staff Ex. 13.0, pp. 4, 12).

Staff also disputes the Company's testimony suggesting that if recovery of pension assets in rates is disallowed, the Commission would in effect no longer support direct benefit pension plans for utility workers. (Staff Init. Br., p. 22). Citing Docket 04-0779, Staff states that the Commission has previously denied requests to include pension assets in rate base where such requests have been found to be improper. (*Id.*). Thus, Staff submits that ComEd's attempt to portray this issue as some sort of Commission referendum on support for direct benefit pension plans for utility workers is baseless, and that any attempt to cast this issue in broader terms amounts to a red herring that is neither supported by the facts nor relevant. (*Id.*).

Further, in its Initial Brief, Staff argued that Company's claim that employees consider ComEd's complete compensation package when deciding whether to work for or continue to work for ComEd must be rejected. (Staff Init. Br., pp. 22-23) Staff states Company witness Mitchell was unable to support that statement with actual numbers of employees who had left ComEd due to the status of the pension plan and was unable to quantify the number of potential employees who had turned down a job offer due to the funding status of the pension plan. (*Id.*).

AG

****33** The AG supports Staff's treatment of the Exelon pension contribution where it is consistent with recently-affirmed Commission practice, as set out in ICC Docket's 04-0779, 93-0301 and 94-0041 and described by Staff Witness Ms. Ebrey:

My position, basing pension expense on the latest actuarial valuation, is also consistent with cases in which a pension asset has been at issue. In the recent NICOR gas rate case, Docket No. 04-0779, the Commission disallowed the inclusion of a pension asset at the same time allowing the pension credit to reduce operating expenses. (ICC Docket 04-0779, Order, p. 23). Similarly, the Commission's order in ICC Docket Nos. 93-0301/94-0041 (Cons.) (Order, pp. 10-13) disallowed GTE the recovery on the pension asset in rate base and at the same time reflected the effects of the increased return on the pension fund in the annual cost included as a net pension credit reducing operating expenses.

Staff Ex. 2.0, p. 14:272-280. However, in the event that the Commission declines to adopt Staff's position and elects to allow a return on the pension contribution, the AG also argues in the alternative regarding the appropriate level of such a return.

The AG argues in the alternative that ComEd should not recover a common equity return (including related income taxes) from ratepayers on the $803 million pension contribution financed entirely by debt. Rather, the AG argues that only the Company's actual cost of debt financing should be recoverable. The AG's witness Mr. Effron testified that ‘through the miracle of modern financial alchemy,‘ ComEd raised its proposed revenue requirement by approximately $97.3 million, when the contribution was conservatively determined to cost a maximum of $27 million to finance. Therefore, ComEd's inclusion of the pension contribution in rate base increased its proposed revenue requirement by $70.3 million. The AG, citing ****199** United Cities Gas Co. v. Illinois Commerce Comm'n*, states that this $70.3 million is not a just and reasonable cost of providing service to ratepayers and should be removed.*United Cities Gas Co. v. Illinois Commerce Comm'n,* 163 Ill.2d 1, 23, 643 N.E.2d 719, 730-731, 205 Ill. Dec. 428,439 (Ill. 1994). In addition, because ComEd treats the pension contribution as equity, the percentage of common equity in the capital structure is also higher, which increases both the rate of return and the total return requirement. CCC witness Mr. Bodmer proposes to reverse the effect of this equity treatment in his proposed rate of return, which the AG agrees with. The AG also asserts that, consistent with *United Cities*, the Commission should find ComEd's proposed treatment of the return on its pension contribution unlawful to dissuade utilities from similar tactics in future rate cases.

To limit the Company's revenue requirement effect of the pension contribution to its actual cost, the AG's witness Mr. Effron suggests two mathematically equivalent alternatives. First Mr. Effron recommends that the pension contribution be eliminated from equity in the determination of the capital structure and rate of return. This reduces the common equity in the capital structure by $802,971,000. [FN5] Then Mr. Effron eliminates the pension contribution from the deferred debits included in rate base. The effect of this adjustment, net of associated ADIT, is to reduce the Company's rate base by $538,855,000. Finally, Mr. Effron included the interest on the pension contribution net of deferred taxes in *pro forma* operating expenses. This adjustment increases *pro forma* jurisdictional expenses by $26,997,000.

****34** Mr. Effron's second alternative treatment, proposes to (1) subtract the pension contribution of $802,971,000 from the common equity in the capital structure on the Company's Schedule D-1 and add that amount, carrying a rate of 5.01%, to the long term debt on that schedule; (2) keep the pension contribution net of associated accumulated deferred income taxes in rate base; and (3) make no adjustment to expenses for the interest on long term debt supporting the net pension contribution. [FN6]

The AG also asserts that ComEd failed to recognize the full annual effect of the return component of the periodic pension cost from the $803 million pension contribution made by Exelon. The pension contribution was made in March 2004. According to the AG By including the full amount of that contribution in rate base, ComEd proposes to include the full annual return requirement associated with the pension contribution in its revenue requirement, while recognizing only 9 months of the return component of the periodic pension cost, based on the March 2005 contribution date. The AG asserts that this arbitrary distinction results in an unbalanced reflection of the effects of the pension contribution. Therefore, to be consistent and recognize the concomitant full annual effect of the contribution on the return component of the periodic pension cost, the AG's witness Mr. Effron proposes to increase the credit for the return component included in the jurisdictional test year pension expense by $8,563,000 and reduced the *pro forma* pension expense by $8,563,000.

Commission Analysis and Conclusion

At issue here is a contribution from Exelon to ComEd to fund ComEd's pension trust fund. In March 2005, Exelon contributed $2 billion to its corporate-wide pension plan because it was ‘the right thing to do.‘ To achieve this, Exelon issued $1.4 billion in debt at 5.01% interest and obtained $600 million in tax credits. According to ComEd, prior to the $803 million contribution for its share of the pension fund, the funding status of the pension plan was at the very low end of the spectrum for large companies. After the contribution, it was more in line with those of other companies and ComEd's goals for itself. ComEd further claims that its only other option to fully fund its pension trust fund was to issue debt, which would have caused its credit rating to be downgraded and would have reversed the effects of its Accelerated Liability Management program. Moreover, ComEd maintains that employees are well aware of troubles experienced by companies that have not adequately funded pension plans, and have ***200** more confidence in ComEd's pension plan because of the fully-funded status.

According to Staff, no pension asset exists. For such asset to exist, the pension fund would need to contain funds in excess of its pension obligations. ComEd readily admits to the pension trust fund being fully funded, not over funded. Since the pension trust fund is not over funded, no pension asset exists. Staff further argues that ComEd failed to meet its burden to prove that the pension 'asset' is used and useful in providing delivery services.

****35** The Commission finds Staff's arguments persuasive. Accounting principles, as well as common sense, dictate that no pension asset exists given that Exelon's infusion in ComEd's pension trust fund does not result in over funding. Further, even if the Commission were to find that a pension asset exists, this would not excuse ComEd from providing evidence that this particular method of funding the pension trust fund is reasonable before the Commission would allow it to be included in rate base. Simply stating that the contribution came from shareholders does not automatically make it reasonable. While the Commission is sympathetic to ComEd's concerns about its credit rating being downgraded if it issues debt to fund its pension obligations, the Commission may have been more sympathetic if ComEd had provided evidence of the cost of that debt and how it would compare to the cost of shareholder supplied funds. Or, perhaps ComEd could have shown how much it would cost ComEd to borrow the funds from Exelon instead of Exelon providing an equity infusion, given that debt tends to be less expensive than equity. Simply stating that credit rating concerns exist is not enough. Additionally, it is not clear why ComEd chose to fully-fund its pension obligations when it did. It seems that the timing of the funding also would affect the cost. The Commission needs to see numerical analyses to be able to perform an effective analysis of a utility's request for rate relief.

ComEd claims that the Commission does not want to establish perverse financial incentives by adopting adjustments that would encourage utilities to fund only the minimum requirements for a pension plan and would deny cost recovery when the Company prudently funded more than that level. From our perspective, we also do not want to establish perverse financial incentives by allowing ComEd's parent company to profit from its inexpensive debt and tax breaks by tucking the funds away in a regulated utility's rate base. This is not to say that the Commission encourages utilities to neglect their pension obligations. Rather, the Commission encourages utilities to consider all options for funding pension obligations and provide a thorough explanation of all options considered before asking ratepayers to shoulder some or all of the expense, be it through rate base or the revenue requirement.

Staff's citations to prior Commission orders addressing ratepayer-funded pension contributions are instructive in the determination of the appropriate level of pension expense. Both of the cases cited by Staff, the Nicor Gas ICC Docket 04-0779 Order and the *GTE* ICC Docket 93-0301/94-0041 (cons.), Order, make clear that the appropriate level of pension expense is determined by an updated actuarial study and is totally separate from the ratemaking treatment of a pension asset. Thus, these Orders serve as precedent for how the pension expense should be treated in this proceeding.

The Commission rejects Mr. Effron's alternative, fallback proposal to remove the pension asset from rate base, but to add to jurisdictional operating expense approximately $27 million, representing the cost of debt financing for the contribution. This alternative simply moves the impact of the pension contribution from a rate base item to an operating statement item and does not change the final revenue requirement.

****36** The record shows that the pension expense based on the updated actuarial study is $11.7 million, which has been reflected in both Staff's and ComEd's proposed revenue requirement. The Commission finds the proposal to reflect this reduction appropriate. In conclusion, the Commission accepts Staff's recommendation to reduce ComEd's rate base by $853.9 million along with the corresponding adjustments to ADIT.

****201*** *4. ACCUMULATED DEFERRED INCOME TAXES*

ComEd

[19] ComEd states that its final revised proposed rate base figure included a correctly calculated final revised figure of $1,408,375,000 for Accumulated Deferred Income Taxes (‘ADIT‘). (Hill Sur., ComEd Ex. 36.0 Corr., Sched. 1 Rev., p. 4). ComEd explained that ADIT is subtracted from plant balances in calculating rate base. (*E.g.* , *id.*).

ComEd states that Staff's and intervenors' proposed adjustments to ComEd's ADIT were entirely derivative of their proposed adjustments to ComEd's plant balances in its proposed rate base. ComEd explained, however, that because those underlying proposed adjustments to ComEd's plant balances are without merit, their derivative adjustments to ComEd's ADIT figure also are without merit.

Staff

As noted above, Staff witness Ms. Ebrey testified that the Company's *pro forma* adjustment to include a ‘pension asset‘ in its proposed rate base should be reversed. (Staff Ex. 2.0, pp. 3-13). Ms. Ebrey asserts that her ‘pension asset‘ adjustment requires a decrease to ADIT. (Staff Ex. 2.0, pp. 12-13).*See* Section III..3 for a discussion of Staff's Position with respect to the Company's proposed pension asset.

AG

To be consistent with proposed adjustments to *pro forma* plant in service and the pension contribution included in deferred debits, the AG's witness Mr. Effron adjusted the related ADIT for a net adjustment of $177,739,000 to the Company's proposal.

Commission Analysis and Conclusion

Staff and the AG have proposed adjustments to ComEd's rate base. As discussed previously in this Order, the Commission has rejected several of the intervenors' proposed adjustments to ComEd's plant balances and therefore rejects the corresponding adjustments to ADIT. The ADIT as reflected in the Appendix to this Order is hereby approved.

5. CUSTOMER DEPOSITS

ComEd

[20] ComEd contends that Staff's proposal to reduce ComEd's proposed rate base by $31,477,000 (along with a related increase of $412,000 in operating expenses) based on the theory that customer deposits are a ‘cost-free source of capital‘ (Ebrey Dir., Staff Ex. 2.0, 27:572-83 and Sched. 2.6; Ebrey Reb., Staff Ex. 13.0, 25:520-26:537 and Sched. 13.5), lacks merit, is inconsistent and unfair, and should be rejected.

First, ComEd asserts that Staff's proposal is unwarranted and one-sided. ComEd explains that customer deposits are a short-term liability on ComEd's books, and thus just one of the many components that constitute ComEd's cash working capital requirements. (Hill Reb., ComEd Ex. 19.0 Corr., 27:560-62). ComEd states, however, that it has not included cash working capital requirements in its proposed rate base. (*E.g.*, ComEd Ex. 5.1, Sched. B-1 Errata). Thus, ComEd argues, Staff selectively picked just two components of cash working capital, customer deposits and the budget payment plan balances, to incorporate in ComEd's rate base. ComEd further avers while both of these cash working capital components would reduce rate base, many of the other cash working components (which Staff ignored) would increase ComEd's rate base. (*See* Hill Reb., ComEd Ex. 19.0 Corr., 27:562-64). In ComEd's opinion, such a result would be inappropriate and unfair.

****37** According to ComEd, in *Commonwealth Edison Co.*, ICC Docket 01-0423 at 46 (Order March 28, 2003), the Commission rejected Staff's proposed adjustment to rate base founded on budget payment plan balances for that reason, stating:

***202** The Commission finds that ComEd's position on this issue is persuasive. While Staff makes a salient point relative to the Company' s exclusion of working capital from this proceeding while in the previous DST proceeding it chose to include working capital, to simply pick out particular working capital items that would result in a downward adjustment to the Company's revenue requirement would be inappropriate. The downward adjustment sought by Staff, therefore, is not accepted.

ComEd maintains that the same reasons that prompted that ruling have been proved in this case. ComEd argues that the Commission in that Docket did approve customer deposits as a subtraction from rate base, *id.* at 115, but ComEd had proposed the subtraction there and did not make the same argument as to customer deposits there. ComEd states that it has made the argument here.

Second, ComEd opines that Staff's witness' position is inconsistent with her proposed adjustment to remove ComEd's pension asset from rate base and, again, one-sided. ComEd asserts that its shareholders have supplied $803 million of capital in the form of the pension contribution that created the pension asset, resulting in a $30 million reduction in pension expenses included in the revenue requirement. ComEd argues that to propose to disallow the inclusion of the pension asset in rate base, while simultaneously insisting that rate base be reduced by $31,477,000 for customer deposits, is inconsistent and unfair. ComEd attests that there is no valid basis for denying shareholders a return on funds they have provided while giving customers a return on funds they have provided (by reducing rate base).

Staff

Staff witness Ms. Ebrey proposes an adjustment to the Company's rate base to reflect the December 31, 2004 balance of customer deposits. Ms. Ebrey testified that customer deposits should be used to decrease rate base for ratemaking purposes because customer deposits represent funds provided by ratepayers rather than shareholders and thus, represent a cost-free source of capital for the Company. (Staff Ex. 2.0, p. 27).

In response to ComEd's rebuttal testimony, Ms. Ebrey testified that, in her experience analyzing cash working capital as a component of rate base, the most frequently used basis for the derivation of a Cash Working Capital requirement, especially for the larger utilities, is a lead/lag study. (Staff Ex. 13.0, p. 26). She states that she has never seen a utility include customer deposits as a source of funds in a lead/lag study. (*Id.*). However, recognizing ComEd's obligation to pay interest on customer deposits, Ms. Ebrey did include interest on customer deposits in the Company's operating expenses. (*Id.*).

Commission Analysis and Conclusion

****38** Staff proposes to reduce rate base by $31,477,000 to reflect the December 31, 2004 balance on customer deposits. ComEd contends that Staff's proposal to reduce rate base by $31,477,000 lacks merit and is inconsistent with prior Commission decisions and unfair. While Staff makes an intriguing point, the Commission will follow its decision on a similar issue in Docket No. 01-0423.Staff chose to include customer deposits in rate base resulting in a rate base reduction on the premise that it is a cost free source of capital. The Commission declines to accept an adjustment solely because the effect of the particular adjustment would result in a rate reduction.

6. BUDGET PAYMENT PLAN

ComEd

ComEd asserts that Staff's proposal to reduce ComEd's proposed rate base by $529,000, based on a theory that budget payment plan balances are ‘excess funds‘ that ComEd may use (Ebrey Dir., Staff Ex. 2.0, 27:585-28:600 and Sched. 2.7; Ebrey Reb., Staff Ex. 13.0, 26:539-27:566 and Sched. 13.6), lacks merit, is inconsistent and unfair, and ***203** should be rejected for the same reasons that Staff's proposed customer deposits adjustment should be rejected. ComEd states that the Commission rejected Staff's parallel budget payments payment balances proposal, based on that first reason, in *Commonwealth Edison Co.*, ICC Docket 01-0423 at 46 (Order, March 28, 2003). In ComEd's opinion, the same reasons that prompted that ruling have been proved in this case.

Staff

Staff witness Ms. Ebrey proposes an adjustment to ComEd's rate base to reflect the 13-month average balance of budget payment plan balances (‘BPPB‘) based upon the most recent 13-month period provided. Ms. Ebrey testified that a 13-month average is a more representative method for the determination of BPPB than a single point in time due to the volatility and seasonality of the BPPB. (Staff Ex. 2.0, p. 28). She asserts that ComEd did not reflect BPPB as a reduction to its jurisdictional rate base in this proceeding since it is not requesting a component for cash working capital (Company Schedule B-14).(*Id.*). Ms. Ebrey states that had the Company chosen to request an allowance for cash working capital in its test year rate base, the impact for BPPB would have been a reduction to that allowance. (*Id.*). She further testified that for the last 2 years of data provided, the Company has over collected from its budget plan customers for their electric service and has had use of those excess funds. (*Id.*). She testified that the BPPB represent funds provided by the ratepayers rather than shareholders and thus should decrease the balance on which the Company may earn a return. (*Id.*).

In her rebuttal testimony, Ms. Ebrey asserted that the Commission has viewed the Customer Deposits and BPPB as completely separate issues from cash working capital in recent rate cases. (Staff Ex. 13.0, p. 27). She states that in most cases, the Commission has approved the reduction of rate base for Customer Deposits as a separate item from the Cash Working Capital allowance in rate base. (*Id.*). Ms. Ebrey avers that the treatment requested by the Company in this case as well as the treatment of Customer Deposits and Budget Payment Plan balances in ComEd's last delivery services case are the only exceptions to the Commission's long-standing practice. According to Ms. Ebrey, since ComEd has not provided support for the Commission to change from this long-standing practice, Staff's adjustments for Customer Deposits and Budget Payment Plan Balances should be approved. (*Id.*).

****39** In addition to the foregoing, in its Initial Brief, Staff argues that ComEd's attempt to draw a comparison between the cash provided by ratepayers through BPPB and cash provided by shareholders to offset ComEd's needs to obtain capital from some other source (*i.e.* funding of the pension plan) should be rejected. (Staff Init. Br., p. 29) Staff maintains that the relevant distinction is that the BPPBs represent an overpayment of amounts owed to the Company by its ratepayers, whereas the shareholder-provided funds used to fully-fund the pension plan do not represent an overpayment by the shareholders.

Commission Analysis and Conclusion

Staff proposes a reduction to rate base of $529,000 for BPPB funds. ComEd asserts that Staff's position is inconsistent and unfair. Staff argues that had the Company requested an allowance for cash working capital in its test year rate base BPPB would have resulted in a reduction to that allowance. In recent years the Company has over collected on BPPB and has had use of these funds which represent ratepayer funds. As with Customer Deposits, discussed above, the Commission believes Staff's position to be intriguing. However, the Commission will follow its decision on this issue as decided in Docket No. 01-0423.The Commission declines to accept Staff's proposed adjustment on this issue.

7. MATERIALS AND SUPPLIES INVENTORY

ComEd

***204 [21]** ComEd includes in its proposed rate base its inventory of materials and supplies as of December 31, 2004, the last day of the test year. (*E.g.*, Hill Dir., ComEd Ex. 5.0 Corr., 16:330-40; ComEd Ex. 5.1, Scheds. B-1 Errata, B-8.1).

ComEd asserts that Staff's proposal to use the 13-month average of ComEd's materials and supplies inventory, less a figure for accounts payable associated with the materials and supplies inventory - which would result in a net deduction from rate base of $1,609,000 (Ebrey Dir., Staff Ex. 2.0, 28:602-29:625 and Sched. 2.8; Ebrey Reb. Staff Ex. 13.0, 28:568- 29:594 and Sched. 13.7) - is incorrect and inappropriate on multiple grounds. ComEd argues that: (1) the 2004 year-end figure is more representative of the current inventory management policies and practices; (2) the 2004 year-end figure is within 3.4% of Staff's 13-month average, disproving any notion that the year-end figure is unrepresentative; (3) Staff used a four-year average to calculate the accounts payable offset part of her proposed adjustment, not the comparable 13-month period it used to calculate the materials and supplies inventory, which is inconsistent and inappropriate; (4) had Staff used the four-year average methodology for both parts of its proposed adjustment, then the result would be a $5,268,000 increase in the test year materials and supplies inventory (before functionalization and the accounts payable offset); (5) Staff disregarded ComEd's direct assignment of the inventory for functionalization purposes, without explanation, and substituted an arbitrary allocator, one that is based on the same point in time, year-end 2004, that Staff rejects when used to calculate the inventory in the first place; and (6) had Staff used the average of the 13-month averages over the last four years then the result would be a $6,681,000 increase in the test year materials and supplies inventory (before functionalization and the offset). (Hill Reb., ComEd Ex. 19.0 Corr., 29:599-31:649 and Sched. 10; Hill Sur., ComEd Ex. 36.0 Corr., 25:566-26:585).

Staff

****40** Staff witness Ms. Ebrey proposes an adjustment to decrease the Company's test year materials and supplies inventory balance based on an average of the most recent thirteen months of balances provided by the Company. Ms. Ebrey testified that a thirteen month average is more representative of the balance over time than the year-end balance proposed by the Company due to the volatility of the materials and supplies inventory balances. (Staff Ex. 2.0, pp. 28-29).

In rebuttal testimony, Ms. Ebrey states that the facts contradict ComEd's argument that the year-end balance better reflects its current inventory management policies and practices and that the year-end balance is representative of balances throughout the year. (Staff Ex. 13.0, p. 28). Ms. Ebrey attests that ComEd's monthly data illustrates the volatility on a month to month basis of the materials and supplies balances over the 4 years of monthly data provided by the Company. (*Id.*). Therefore, Ms. Ebrey argues that the use of a 13-month average is appropriate. (*Id.*). In response to ComEd's rebuttal testimony, Ms. Ebrey revised the accounts payable portion of her adjustment so that it is based upon the average for the test year rather than a 4-year average. (*Id.*, pp. 28-29).

Commission Analysis and Conclusion

ComEd proposes to include its materials and supplies inventory in rate base as of December 31, 2004, the last day of the test year. Staff alternatively proposes a decrease to ComEd's materials and supplies inventory based on an average of the most recent thirteen month balances provided by ComEd. At issue here is whether or not the close of the test year is the appropriate measure for ComEd's materials and supplies inventory. The Commission accepts ComEd's proposal as reasonable. The record in this docket provides that ComEd's proposed figure more accurately reflects ComEd's present inventory management policies and practices.

****205** 8. PROCUREMENT CASE EXPENSES [RATE BASE EFFECT]; RATE CASE EXPENSE [RATE BASE EFFECT]*

[22, 23] ComEd seeks to recover its legal fees and expenses associated with the Rate Case and the Procurement Case through inclusion of those costs in the test year rate base. According to ComEd, Staff does not disagree with ComEd that such costs are recoverable. (Hathhorn, Tr. at 1720:14-18). Nor does Staff object to amortizing Rate Case expenses over a three-year period. (Hathhorn, Tr. at 1718:22-1719:2). ComEd and Staff have two principal disagreements: (1) where to recover the Procurement Case expenses (delivery services charges (ComEd) or supply administration charge (‘SAC‘) (Staff)); and (2) if both the Procurement Case expenses and Rate Case expenses are recovered through delivery service charges, whether there should be a return on the unamortized balances of the Rate Case and Procurement Case expenses. (Hathhorn, Tr. at 1720:2-18; Hill Sur., ComEd Ex. 36.0 Corr., 26:587- 98).

Apart from the issues of recovery mechanism and the potential return on the unamortized balances, Staff and CCC also propose certain rate case and procurement case expense adjustments. Staff witness Dianna Hathhorn proposes to reduce the procurement case expenses by $566,667 because she finds the estimated costs of two vendors not shown to be just and reasonable by ComEd. (Staff Ex. 12.0, Schedule 12.11, page 2). Ms. Hathhorn's adjustment also disallows $626,000 in rate case expense amounts because she finds the estimated amounts to be unsubstantiated by ComEd. (Staff Ex.

1.0, Schedule 1.12 and Staff Ex. 12.0, Schedule 12.12).

****41** CCC alleges that ComEd has failed to provide sufficient justification for its requested 67% increase in rate base expense and states that the proposed rate case expense adjustment of $9,193,000 is almost as much as the two previous DST cases combined (Dockets 99-0117 and 01-0423). CCC asserts that ComEd included amounts in its forecasts that are not known and measurable and do not appear reasonable. CCC Ex. 5.0 at 20-21, L. 399-408. Mr. McGarry therefore recommended that ComEd's proposed rate case expenses be reduced by $1.036 million, which represents the difference between the 2005 known and measurable expenses and ComEd's original estimate, as set forth in its Schedule C-10 filing, plus 41.8% of ComEd's estimated 2006 rate case expenses ($0.2599 million).*Id.* at 21-22, L. 417-444. The basis of this adjustment is the ratio of actual expenses paid to experts and consultants in 2005 (41.8%) applied to the estimated expenses as originally filed on Schedule C-10 ($910,000).*Id.* at 22, L. 432-433. CCC states that ComEd's updated rate case expense, Exhibit 48.0, claims that its total rate case expense is now $9,832,973, or $639,856 more than what it originally requested and that the updated amount still includes about $1.784 million in projected expenses, thus allegedly continuing to violate the Commission's known and measurable standard. Further, CCC points out that the projected amounts are allocated to litigation of the instant proceeding. Considering the parties are now at the post-hearing briefing stage of the case, CCC argues that ComEd's projected $1.784 million in rate case expense appears unwarranted and unreasonable on its face.

ComEd opines that Staff's proposal to disallow certain rate case expenses was without merit. (Hill Reb., ComEd Ex. 19.0 Corr., 33:683-34:715; Hill Sur., ComEd Ex. 36.0 Corr., 28:642-648; ComEd Ex. 48.0).

ComEd maintains that Mr. McGarry is mistaken in suggesting that ComEd's rate case expenses are higher than the amount approved in the previous rate case. Mr. Hill testified (Hill Reb., ComEd Ex. 19.0, Corr., 34:716-36:749) that the Commission allowed ComEd to recover $5,498,000 in its last rate case, but that amount only included the first phase of a two-phase case, and ComEd's actual rate case expense was ultimately $10,133,000 (not including the $6,517,000 associated with the Liberty rate case audit). The proposed test year rate case expense of $9,193,000 is therefore *less than* ComEd's actual experience in its previous rate case. As to Mr. McGarry's questioning about costs related to rebuttal witnesses, ComEd ***206** maintains it was providing a good faith estimate of its rate case expenses at the time of filing the initial case, and has since provided updates to these expenses. (Hill Reb., ComEd Ex. 19.0 Corr., 33:683-34:715, 35:737-749; Hill Sur., ComEd Ex. 36.0 Corr., 28:642-658; ComEd Ex. 48.0).

Commission Analysis and Conclusion

Before we address the issue of which recovery mechanism is most appropriate for procurement case expenses, the Commission will adjust Administrative and General expense (1) to reduce the rate case expense to be recovered by ComEd by Staff's proposed adjustment of $626,000 and (2) to reduce the procurement case expense to be recovered by ComEd by Staff's proposed adjustment of $566,667 because we agree with Staff that these amounts were not fully substantiated by ComEd. We decline to make further adjustments proposed by CCC because ComEd showed that its proposed rate case expense amount is less than its previous actual rate case expenses and ComEd's filed updates to its initial expense estimates appear reasonable.

****42** *9. PROCUREMENT CASE EXPENSES RECOVERY MECHANISM*

ComEd

[24] ComEd states that it should recover its Procurement Case expenses through delivery services rates. ComEd asserts that these costs are for the benefit of all customers, not just those that take supply service from one of ComEd's supply tariffs. (Crumrine Reb., ComEd Ex. 23.0, at 7:138-42). ComEd argues its statutory obligation under Section 16-103(a) of the Act, 220 ILCS 5/16-103(a), to make supply service available to most retail customers and that, under the Procurement Case

Order, it is offering supply service options to all customers. ComEd attests that if a delivery services customer in the future comes back to ComEd, ComEd must have sufficient supply to meet that customer's supply needs. (Crumrine Reb., ComEd Ex. 23.0, 7:138147; Hathhorn, Tr. at 1724:6-10). ComEd states that this ability to return to ComEd for supply clearly is a benefit to that customer. (Crumrine Reb., ComEd Ex. 23.0, 7:142144; Hathhorn, Tr. at 1722:20- 1723:2). Accordingly, ComEd maintains, the Commission's decision in the Procurement Case creates the foundation for the competitive ‘safety net‘ to be extended to retail customers under Illinois law in the post-transition period. (Crumrine Reb., ComEd Ex. 23.0, 7:148- 8:151).

ComEd asserts that Staff's proposal for recovering Procurement Case expenses through the SAC (Hathhorn, Tr. at 1720:6-1721:4) is inconsistent with traditional ratemaking principles. ComEd opines that such a proposal fails to recognize that such costs incurred are for the benefit of all customers.

More generally, ComEd states, the Procurement Case costs at issue are the costs incurred so that ComEd can fulfill all of the supply obligations noted above in this section of this Order, including its obligations as a provider of last resort. (Crumrine Reb., ComEd Ex. 23.0, 7:138-142; Hathhorn, Tr. at 1723:3- 1724:13). ComEd further states that by allowing it to recover the unamortized balance of Procurement Case expenses through delivery services rates, the Commission will ensure that all parties benefiting from the Procurement Case bear some of the related expense, *i.e.*, the expense will be passed on to both bundled and delivery service only customers through the delivery services charge. (Crumrine Reb., ComEd Ex. 23.0, 6:125-7:132, 8:167-9:169; ComEd Ex. 5.1, Sched. C-2.10).

ComEd argues that Staff's proposal that ComEd recover its unamortized balance of the Procurement Case expenses solely though the SAC would impose on residential customers an unfairly high portion of the Procurement Case expenses. (Crumrine Reb., ComEd Ex. 23.0, 8:159-167; Hathhorn, Tr. at 1726:6-22). ComEd attests that the SAC applies only to supply customers who chose ComEd as their supplier, and that all customers taking supply as well as delivery from ComEd, *i.e.*, all of ComEd's bundled customers, pay a SAC. (Crumrine Sur., ***207** ComEd Ex. 40.0, 45:1035 - 46:1041; Hathhorn, Tr. at 1721:5-18). ComEd avers that most bundled customers today are residential customers, and that delivery services only customers do not pay a SAC. (Hathhorn, Tr. at 1725: 21-1726:5). Thus, ComEd states, its large industrial and commercial delivery customers who take service from another supplier do not pay a SAC unless they come back to ComEd for service at some later time. (Crumrine Reb., ComEd Ex. 23.0, 8:158-163; Hathhorn, Tr. at 1726:18-1727:6). ComEd opines that for this reason, Staff's proposal would allow large industrial and commercial customers with competitive options to avoid Procurement Case costs by switching to or staying with another supplier, and they would help pay for such costs only if they exercised their option to return one day to take supply from ComEd. (Crumrine Reb., ComEd Ex. 23.0, 8:158-67). In other words, ComEd maintains, under Staff's proposal, residential and small commercial customers would be most likely to bear most of the costs of the Procurement Case.

****43** Moreover, ComEd states that Ms. Hathhorn's claim, that the benefits from the Procurement Case are ‘ *de minimis‘* for customers that do not take supply from ComEd (Hathhorn, Tr. at 1754:1-4), is not credible. ComEd avers that by putting the obligation to serve requirement in the Act, the General Assembly made clear that it did not share Ms. Hathhorn's view that this requirement is merely a ‘*de minimis‘* benefit. ComEd further argues that even these customers that ComEd is not obligated to serve have fought to maintain the supply option. (*Commonwealth Edison Co.*, ICC Docket 05-0159, (Order, Jan 24, 2006), at 124-130).

Staff

Staff witness Dianna Hathhorn opposed ComEd's proposal to amortize ComEd's estimated legal fees and expenses related to the procurement proceeding, Docket No. 05-0159, because the costs are not related to delivery services. Instead, she recommended those costs be recovered through the Supply Administration Charge

('SAC'). Her proposal assigns the cost of the procurement proceeding to those customers who benefit from the procurement process rather than to *all* customers including those who do not take supply from ComEd and those whose electric supply service has been declared competitive.

Ms. Hathhorn further testified that an example of the inequity in ComEd's proposal to include costs from the procurement proceedings in delivery services rates, is that some of the expenses included in ComEd's procurement expense request are for an auction manager and staff, auction management expenses, and an auction advisor, but adopting ComEd's proposal would charge customers who only take delivery services from ComEd with costs related to ComEd's procurement proceeding and operations. (ICC Staff Exhibit 1.0, p. 19)

Staff, in its Initial Brief in response to ComEd's argument that '[t]he availability of this default supply service is a benefit to all retail customers, whether they take ComEd electric supply service or not' (ComEd Ex. 23.0, p. 7), argues that ComEd's argument is flawed because the obligation to serve existed before the procurement proceeding. (Staff IB, p. 60) Staff added that the procurement proceeding changed the method by which ComEd will obtain supply to meet this *existing* obligation, but it did not establish the obligation. The obligation to serve, and thus the availability of supply, remains unchanged by the procurement proceeding. (*Id.*) While Ms. Hathhorn did admit at the hearing that there may be a *de minimus* benefit to all customers of the procurement proceedings, (Tr., p. 1754), under her proposal customers are only charged when they procure power supply from ComEd. (*Id.*)

Ms. Hathhorn's testimony pointed out another inequity of ComEd's proposal by examining the impact on customers with demands greater than 3 megawatts ('>3 MW customers'). She stated that in ICC Docket No. 05-0159, >3 MW customers argued that their service offering should be procured through fixed price products; however, ComEd declined this proposal. [FN7] Ms. Hathhorn noted that by charging the >3 MW customers procurement case fees and expenses, these customers will ***208** pay for a service they are eligible for but may not want. (ICC Staff Exhibit 1.0, p. 20).

****44** In its Initial Brief, Staff identified the inconsistency in ComEd's proposal. Staff noted that ComEd's proposal charges some procurement expenses to all DST customers (ComEd Schedules WPB-2.3 and C-10) yet other procurement expenses are segregated and charged only through the SAC (ComEd Ex. 10.7). (Staff IB, p. 61) Staff argued that it is unclear how ComEd made - and will make in the future - the determination between which procurement expenses should affect the delivery services charge and which expenses affect only the SAC. Staff noted that ComEd has identified no valid reason for its inconsistent approach. (Staff IB, p. 61; ICC Staff Exhibit 12.0, pp. 18-19).

CES

CES argues that legal fees and expenses associated with ComEd's procurement case (ICC Docket No. 05-0159) should be recovered through ComEd's SAC rather than through delivery service charges. CES recommends that the Commission adopt Staff's adjustment in this regard, since costs should be allocated properly between delivery services and supply or generation-related costs. (*See* CES Ex. 5.0 at lines 141-48; CES Initial Br. at 20.)

Commission Analysis and Conclusion

At issue is whether or not ComEd should be allowed to recover the costs associated with the procurement case through its delivery service rates. ComEd argues that it should be allowed to recover the costs incurred as a result of the procurement case through delivery service rates as those costs are ultimately a benefit to all customers. Staff opposes ComEd's proposal and in the alternative proposes that ComEd only be allowed to recover its unamortized balance of its procurement case expenses through the SAC. Staff's proposal assigns the cost of the procurement proceeding to those customers who benefit from the procurement process rather than to all customers including those who do not take supply from ComEd and those whose electric supply service has been declared competitive. The Commission agrees with Staff that ComEd's proposal to amortize its estimated legal fees and expenses related to the procurement proceedings should be rejected since the costs are not related to delivery services. The Commission finds Staff's proposal more closely aligns with cost causation principles. The reduction to procurement expense referenced in the preceding sentence which was derived from Staff Exhibit 12.11, page 2 of 2, lines 5-10, will reduce the amount of the procurement expense ComEd will be allowed to collect through the Supply Administration Charge, which is discussed later in the Order. For this reason, the Commission deems Staff's proposed recovery methodology reasonable and it is hereby adopted.

10. RECOVERY OF UNAMORTIZED BALANCES OF RATE AND PROCUREMENT CASE EXPENSES

ComEd

ComEd proposes to include in its rate base the unamortized balance of the Rate Case expenses, as well as the unamortized balance of the Procurement Case expenses. (Crumrine Dir., ComEd Ex. 9.0 Corr., 45:984-46:1006; Hill Dir., ComEd Ex. 5.0 Corr., 16:348-17:354, 33:708-34:725). ComEd asserts that the rate making principle is that it should recover the time value of money for its outlay of Rate Case and Procurement Case expenses over the period that one expects the full costs to be recovered. That is, as ComEd proposes, the period of time that rates set in this proceeding are to be in effect. (Hill Sur., ComEd Ex. 36.0 Corr., 26:596-98). ComEd states that by including the unamortized balance of these expenses in the rate base, shareholders are not earning a profit on them, but rather they appropriately are being reimbursed for their ‘carrying costs‘ for the time period over which they receive full reimbursement for these just, reasonable, and approved expenses. (Hill Reb., ComEd Ex. 19.0 Corr., 32:664-67).

****45** ComEd states that Commission history and ***209** the facts of this case both establish that Staff's arguments are without merit. ComEd avers that although Staff claimed that inclusion of the unamortized balances in rate base could lead to rate payers being overcharged because the amortization period might expire before ComEd had a new rate case (Hathhorn, Tr. at 1729:6-20), Staff agreed that a three-year amortization period is appropriate in this case for the recovery of the expenses of this rate case. (Hathhorn, Tr. at 1730:16-20). ComEd asserts that history shows that the Commission consistently has decided that a three-or four-year amortization period is a reasonable expected life of the rates set within ComEd rate case proceedings. (Hill Sur., ComEd Ex. 36.0 Corr., 26:599-27:601). In addition, ComEd opines that history also shows that in each instance, the Commission's decisions have been accurate in that the amortization period fairly matched the actual period between the effective date for the new rates and the filing of the next rate proceeding, particularly when one considers that in each instance, much of the rate case costs were incurred well before the Commission order approving the new rates. (Hill Reb., ComEd Ex 19.0 Corr., 35:722-36; Hill Sur., ComEd. Ex. 36.0 Corr., 26:599-28: 627; Hathhorn, Tr. at 1730:21-1733:12).

According to ComEd, this experience shows that had the Commission included the unamortized balances of rate base expenses in the rate base in Docket Nos. 90-0169 and 94-0065, the Commission's determination of the amortization periods would have been fair symmetry in that the amortization period would have fairly matched the actual period between the effective date for the new rates and the filing of the next rate proceeding. ComEd opines that such inclusion would have resulted in shareholders appropriately receiving time value for their money and ratepayers not being overcharged due to amortization periods being too short. (Hill Sur., ComEd. Ex. 36.0 Corr., 28:628-30).

Moreover, ComEd asserts that in each of its last two rate cases, the Commission did in fact approve recovery by ComEd in rates of the unamortized balance of rate case expenses. (Hill Reb., ComEd Ex. 19.0 Corr., 33:679-82). ComEd argues that the facts do not show overrecovery of such costs. With respect to Docket No. 99-0117, ComEd states that the three-year amortization period did not expire before ComEd filed a new rate case. (Hill Sur., ComEd Ex. 36.0 Corr., 27:616-20). Also, with respect to Docket No. 01-0423, ComEd states that although the expected effective dates for the rates to be set in this proceeding are January 2007, a period of 4 years and 9 months, much of the costs were incurred well before the Order issued in that case and significant costs after the Interim Order in that case were not reflected in the revenue requirement. (Hill Sur., ComEd Ex. 36.0 Corr., 27:621-28:627).

Staff

Staff witness Ms. Hathhorn testified that an adjustment is necessary to disallow the Company's request to include its unamortized balance of rate case expense of $3,693,000 in rate base, in order to ensure that there is a fair and equitable allocation of rate case costs between ratepayers and shareholders. Ms. Hathhorn's adjustment also removes the unamortized balance of procurement expense from rate base. (ICC Staff Exhibit 1.0, Schedule 1.11 and ICC Staff Exhibit 12.0, Schedule 12.11). Ms. Hathhorn's procurement case expense adjustment results in a revenue requirement impact of $2,364,000 to operating expense and $2,849,000 to rate base. (ICC Staff Exhibit 12.0, Schedule 12.11) Her position on both of the proposed adjustments is the same since the same principles apply to both adjustments.

****46** Ms. Hathhorn states that her proposed treatment of rate case expense requires shareholders to bear the capital costs associated with improving their investment through increased rates, while ratepayers bear the average annual cost for the continued provision of safe reliable service. Without this treatment, she testified that there is little to no incentive for the Company to keep its rate case expenses to a minimum. (Staff Ex. 1.0, p. 22).

Further, Staff witness Hathhorn asserts that in recent ICC orders for unamortized rate case ***210** treatment where it was a contested issue before the Commission, only one case, ICC Docket No. 99-0117, [FN8] resulted in the inclusion of the unamortized balance of rate case expense in rate base being approved by the Commission. In that case, she states that ComEd successfully argued that the proceeding was markedly dissimilar from general rate case dockets in that the proceeding was initiated by law and not by a utility's request for a rate increase. (Docket No. 99-0117, Order dated August 25, 1999, p. 49) However, Ms. Hathhorn testified that this rate case proceeding was initiated by a utility's request for a rate increase and not by law. Therefore, Staff recommends that the Commission follow its customary practice of allowing amortization of rate case expense but not allowing a return on the unamortized balance. (Staff Ex. 1.0, pp. 22-23).

In responding to ComEd's contention that ‘the only improvement that the shareholders receive [from a rate case] is the re-setting of fair and reasonable returns on their investment‘ (ComEd Ex. 19.0 Revised, p. 30), Staff witness Ms. Hathhorn asserts that in Docket Nos. 94-0065 and 91-0317, the Commission found that Staff's adjustment to recognize the benefits to shareholders resulting from ComEd's rate case process was appropriate. (Docket No. 94-0065, Order dated January 9, 1995, pp. 99-98) (Consumers Illinois Water Company, Docket No. 91-0317, Order dated May 28, 1992, p. 23) (Staff Ex. 12.0, pp. 21-22).

Further, Staff states in its Initial Brief that CCC witness McGarry supported Staff's adjustments to disallow unamortized balances in rate base. (CCC Ex. 5.0, p. 32).

In summary, Ms. Hathhorn testified that her position is based on the premise that the benefits shareholders receive from a rate case are the increased rates. The rates do carry risk of over-charging ratepayers for the costs of the rate case incurred to achieve the increased rates, yet ComEd expects ratepayers to bear this risk, while requiring no such symmetry from shareholders. According to Ms. Hathhorn, expecting the shareholders to share in that risk is reasonable and reflects a common practice of this Commission. (Staff Ex. 12.0, pp. 20-21).

Staff witness Hathhorn testified that for the same reasons, the unamortized balance of procurement case expenses should be disallowed in rate base. (Staff Ex. 12.0, pp. 20-22).

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CCC support Staff's proposed disallowance of $2.364

million of ComEd's estimated legal fees and expenses related to the procurement proceeding in Docket 050159 as an operating adjustment. CCC Ex. 5.0 at 27-32, L. 542-626; Staff Ex. 1.0 at 19, L. 400-402. Mr. McGarry opined that ‘it is important to associate prudently incurred costs of the utility, or in this case, costs that are specifically associated with a service with those customer who use the service.‘ CCC Ex. 5.0 at 29, L. 566-568. Mr. McGarry used the analogy of the auto service station to illustrate his point - a customer who receives an oil change from the service station would not be charged a disposal fee associated with tire disposal, even if that customer could potentially have benefited from a new set of tires.*Id.* at 30, L. 589-592. Likewise, alleges CCC, the costs associated with the procurement case should be borne only by those customers who are taking competitive power. Thus, CCC requests that the Commission disallow $2.364 million of procurement case expense.

Commission Analysis and Conclusion

****47** At issue is the concern over ratepayers being overcharged as a result of unamortized balances being included in rate base. Staff is concerned that if the expenses are not shared, there is little or no incentive for the Company to keep its costs down. Staff's proposal is for the shareholders to share some of the costs of the rate case. The Commission finds ComEd's position on this issue unpersuasive. The amortization period as proposed by ComEd appears reasonable given the estimated life of these rates, however the amortization period alone does not insure a fair and equitable allocation of rate case expense. Staff's proposal recognizes the benefits to shareholders resulting from this rate case, consistent with prior Commission conclusions.***211** Therefore, the Commission accepts Staff's proposal.

11. STAFF ADJUSTMENT RELATED TO COMED SCHEDULE B-2.1

ComEd filed its Schedule B-2.1 as part of its original Part 285 filing. This Schedule listed detailed adjustments to rate base based on ComEd's *pro forma* adjustments for certain 2005 plant. ComEd's Schedule B-2.1 Errata is included in ComEd Ex. 5.1.

Staff proposes certain additional adjustments to ComEd Ex. 5.1, Schedule B-2.1 Errata. Given that ComEd never contested Staff's adjustment with testimony from its own witnesses, but waited until its reply brief to respond to Staff's adjustment, the Commission accepts Staff's adjustment. This results in a downward adjustment of $2,063,000 in Gross Utility Plant, along with corresponding adjustments to accumulated depreciation, accumulated deferred income tax and depreciation expense consistent with Staff Exhibit 14.0, Schedule 14.2.

12. APPROVED RATE BASE

[25] Based on the electric utility delivery services rate base as originally proposed by ComEd along with the conclusions *supra*, the utility rate base for ComEd approved for purposes of this proceeding is $5,521,350,000. The rate base may be summarized as follows:

Approved Rate Base	
(In Thousands)	
Gross Utility Plant	$11,522,026
Accumulated Provision for Depreciation and Amortization	-4,595,450
	____
Net Plant	6,926,576
Additions to Rate Base	

Materials and Supplies	20,030
Construction Work in Progress	41,047
Regulatory Assets	10,757
Deferred Debits	
Deductions From Rate Base	
Accumulated Deferred Income Taxes	-1,189,487
Operating Reserves	-259,980
Asset Retirement Obligation	-1,065
Other Deferred Credits	-24,434
Customer Advances	-2,047
Accumulated Investment Tax Credits	-47
Customer Deposits	0
Budget Plan Balances	0
Rate Base	$5,521,350
	=

The development of the overall electric utility delivery services rate base adopted for purposes of this proceeding is shown in the Appendix to this Order.

IV. OPERATING EXPENSES AND REVENUES

1. DISTRIBUTION O&M

ComEd

[26] ComEd proposed $277,488,000 for Distribution and Operations and Maintenance ('O&M') expenses in its direct testimony. (*E.g.*, ComEd Ex. 5.1, Sched. C-1 Errata). ComEd presented direct testimony from Mr. Costello and Mr. Hill to support ComEd's Distribution O&M expenses included in the revenue requirement. Mr. Costello, in his direct testimony, discussed the nature of these expenses, such as distribution system maintenance expenses that help to maintain the safety and the reliability of distribution service and storm damage repair expenses; he explained how ComEd controls these expenses; and, he discussed the net downward adjustments that ComEd had made in the amount of $1,848,000 to these expenses, resulting in a level that he concluded was necessary, prudent, and reasonable. (Costello Dir., ComEd Ex. 3.0 Corr., 26:567-29:617). In his direct testimony, Mr. Hill further described and confirmed the quantification of, these expenses, ***212** including the adjustments. (Hill Dir., ComEd Ex. 5.0 Corr., 23:500-24:513).

****48** ComEd witness Mr. DeCampli in his rebuttal testimony opined that the bases of CCC's proposed adjustment were speculative. ComEd states that reductions in Distribution O&M expenses in 2003 and 2004 were the result of broad steps to improve efficiency and productivity. ComEd avers that while the cost reductions that were achieved are expected to be sustainable, additional incremental reductions cannot be expected to continue, which all means that CCC's proposal does not reflect operational reality. (DeCampli Reb., ComEd Ex. 14.0 Corr., 13:249-64).

ComEd Witness Mr. Costello, in his rebuttal testimony, states that a further decline in the salaries and wages expenses, the largest component of Distribution O&M expenses should not be expected to occur as suggested by CUB. ComEd asserts that while ComEd experienced a substantial decline in the number of its employees in 2004, another significant decline did not occur in 2005 and additional significant declines should not be expected. (Costello Reb., ComEd Ex. 13.0 Corr., 34:765-35:796). ComEd Witness Ms. Houtsma, in her rebuttal testimony, states that the Exelon Way program, the implementation of which was completed in 2004, and which reduced ComEd's total (all categories) 2004 O&M expenses by $66 million, included, among other things, the transfer of 436 employees out of ComEd on January 1, 2004. (Houtsma Reb., ComEd Ex. 18.0 Corr., 3:46-50, 12:254-56; *see also* Houtsma Sur., ComEd Ex. 35.0, 7:139-9:190).

ComEd, in its surrebuttal testimony, decreased its proposed O&M expense amount by $3,304,000 for a total $274,184,000 for Distribution O&M expenses in its final revised proposed revenue requirement, in order to ensure that certain environmental expenses were excluded from its revenue requirement in accordance with its proposed Rider ECR, discussed later in this Order. (Hill Sur., ComEd Ex. 36.0 Corr., 4:72-89, 5:100-02 and Sched. 1 Rev). ComEd states that its final revised figure should be approved as reasonable and necessary expenses of providing distribution service.

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CCC recommends that the Commission reduce ComEd's O&M expenses by $13.347 million based on the premise that ComEd has a responsibility to pass along any savings that result from capital investments along its customers. (March 23, 2006 Tr. at 967; CCC Ex. 2.0 at 17-18, L. 368-385). According to CCC, ComEd's O&M expenses have steadily declined between the years 2001 through 2004 due to ComEd's investment of over $2 billion dollars in its distribution plant facilities. (*Id.* at 15, L. 332336). Specifically, CCC argues that ComEd's investment in its distribution plant facilities reduced O&M cost through greater efficiency and productivity. (ComEd Ex. 14.0 (Corrected) at 13, L. 256-257). CCC maintain that ComEd's reduction in O&M expenses for the years 2001 through 2004 should be the benchmark for ComEd's O&M expenses in the coming years as ComEd continues to invest in its distribution facilities.

****49** Mr. McGarry testified that since 2001, the Company has experienced an average reduction of 8.2% per year in its distribution operations and maintenance expenses. (CCC Ex 2.0 at 16, L.338-339). This equates to a nearly $82.5 million reduction over the period 2001 to 2004, and an average decline of $27.5 million per year. (*Id.* at 16, L. 339-341). Mr. McGarry opined that this is a result of the significant capital investments the Company made during that period. (*Id.* at 16, L. 348-351). According to CCC, the Company itself acknowledges that its operations include the use of better and more efficient technologies and equipment. (March 21, 2006 Tr. at 254-55). CCC asserts that much of ComEd's plant infrastructure is new and will require less maintenance on a going-forward basis. (CCC Ex 5.0 at 10, L. 191-193).

CCC argue that, though the Company does propose certain specific known and measurable adjustments to its distribution operations and maintenance expenses, which collectively reduce the total distribution O&M by $2.027 million or 0.73%, ComEd fails to acknowledge the inherent overall increase in productivity that is achieved with the use of better and more efficient***213** technologies and equipment, and the Company's incentive compensation program. (CCC Ex 5.0 at 10, L. 191-193). Thus, posits CCC, a productivity adjustment should be made to reflect the fact that the Company's distribution expenses are declining as a result of ComEd's significant investment in upgrading its facilities.

ComEd asserts that the downward trend in O&M expenses cannot be sustained in future years. (ComEd Ex. 14.0 (Corrected) at 13, L. 259-260). Nevertheless, CCC argues that ComEd failed to present any evidence to support its position. During cross-examination, ComEd Witness Mr. DeCampli testified that his assertions that O&M costs were leveling off were not supported with any analyses. Further, Mr. Costello testified that actual O&M expenses for 2005 are trending down from previous years. (March 21, 2006 Tr. at 251). Mr. Costello further testified that ‘[c]ertainly a big driver has been the capital improvements we've made in our system, trying to improve reliability across all of Commonwealth Edison.‘(*Id.* at 254). CCC explains that it is precisely the impact of the capital improvements that prompted Mr. McGarry's adjustment. CCC assert that

ComEd's assertion that the downward trend in O&M expenses cannot be sustained in future years is not supported by the record, is without merit and should be rejected.

CCC proposes a 4.75% downward adjustment to the Company's proposed distribution expenses (which is equivalent to $13.347 million of the Company's proposal before applying other *pro forma* adjustments). (CCC Ex 2.0 at 17, L. 368-370). Mr. McGarry developed this recommended disallowance by observing actual data from 2001 through 2004, which reflects a downward trend in distribution O&M costs. In CCC's opinion, Mr. McGarry did not base his proposed adjustment on the fact that a downward trend exists - he merely used that trend to calculate the proposed adjustment (to be conservative, Mr. McGarry applied a 3.45% inflation adjustment to that trend). CCC assert that a $13.347 million reduction in ComEd's distribution expenses is justified given the historical data produced by ComEd demonstrating that ComEd's investment strategy has reduced its operational and maintenance expenses. CCC maintains that the Commission should ensure that ComEd passes along the benefit of these reduced expenses to ratepayers.

Commission Analysis and Conclusion

****50** ComEd proposes to include $277,488,000 in O&M expenses in rates. CCC recommend that the Commission reduce ComEd's O&M expenses by $13.347 million based on the premise that ComEd has a responsibility to pass along any savings that result from capital investments along its customers. According to CCC, ComEd's O&M expenses have steadily declined between the years 2001 through 2004 due to ComEd's investment of over $2 billion dollars in its distribution plant facilities, creating greater efficiency and productivity. CCC maintain that ComEd's reduction in O&M expenses for the years 2001 through 2004 should be the benchmark for ComEd's O&M expenses in the coming years as ComEd continues to invest in its distribution facilities.

ComEd states that reductions in Distribution O&M expenses in 2003 and 2004 were the result of broad steps to improve efficiency and productivity. According to ComEd, CCC's proposal does not reflect operational reality even. ComEd expects the cost reductions to be sustainable, however it is uncertain whether additional incremental reductions will continue.

Additionally, ComEd does not expect a further decline in the salaries and wages expenses, which are the largest component of Distribution O&M expenses. ComEd experienced a substantial decline in the number of its employees in 2004, although additional significant declines should not be expected. ComEd pointed out that the Exelon Way program, the implementation of which was completed in 2004, reduced ComEd's total (all categories) 2004 O&M expenses by $66 million, and included, among other things, the transfer of 436 employees out of ComEd on January 1, 2004.

CCC was unable to provide either a valid basis for its proposed adjustment or any support ***214** for its claim that ComEd's capital investments in its Distribution system will result in net lower Distribution O&M expenses in the future. The record shows that further significant, incremental decreases in expenses should not be expected to continue and have not been proven to be known and measurable. The Commission finds that CCC's theory about future reductions to be speculative in the absence of supporting information regarding the drivers of that data, and therefore an insufficient basis for an out-of-test year adjustment. The proposed adjustment by CCC is rejected.

2. PENSION AND OTHER POST-RETIREMENT EXPENSES

ComEd

[27] In ComEd's rebuttal testimony, the Company acknowledged that Staff witness Ebrey proposed an adjustment to pension expense based upon the most recent Towers Perrin actuarial report for the 2004 test year. The Company does not oppose this adjustment.

Staff

Staff witness Ebrey proposes an adjustment to update the Company's pension expense based upon the most recent Towers Perrin [FN9] actuarial report for the 2004 test year. Ms. Ebrey states that it has been the Commission's practice to use the actuarially-determined pension expense even in cases where a pension asset is at issue. (ICC Staff Exhibit 2.0, pp. 13-14). Ms. Ebrey testified that her position is consistent with cases in which a pension asset has been at issue, citing two prior Commission Dockets which treated pension expense as a separate issue from the recovery of a pension asset in rate base. (ICC Staff Exhibit 2.0, p. 14).

****51** In her rebuttal testimony, Ms. Ebrey observed that ComEd reflected the same adjustment she proposed in its December, 14, 2005 errata filing. (ICC Staff Exhibit 13.0, p. 12). Ms Ebrey also responded to ComEd's arguments that the actuarially-determined pension expense should be increased if the funding of the 'pension asset' is not added to the Company's rate base. She states that the Company's argument would tie the pension expense to the ratemaking treatment of the Company's discretionary funding of the pension fund rather than the pension expense as determined by the actuary. (*Id.*, pp. 11-12).

Commission Analysis and Conclusion

Staff proposes an adjustment to update the Company's pension expense based upon the most recent Towers Perrin actuarial report for the 2004 test year. In its Rebuttal Testimony, ComEd states that it no longer opposes Staff's proposed adjustment. The Commission finds the adjustment reasonable and approves the adjustment as proposed by Staff and agreed to by ComEd.

3. ADMINISTRATIVE & GENERAL EXPENSES

ComEd

[28-32] ComEd adjusted its proposed A&G expense to remove $25,727,000 of its actual 2004 A&G expenses, including $17,658,000 of executive compensation expenses from its calculations, yielding a figure of $321,909,000, before functionalization. (*E.g.*, Hill Dir., ComEd Ex. 5.0 Corr., 27:575-86; ComEd Ex. 5.2, work paper WPC-1a, pp. 1-3).

ComEd then functionalized that $321,909,000 of A&G expenses, determining that the amount that supported the distribution and customer functions was $287,142,000 and the amount that supported the transmission function was $34,767,000. (Hill Dir., ComEd Ex. 5.0 Corr., 27:582-28:594; ComEd Ex. 5.1, Sched. C-1 Errata; ComEd Ex. 5.2, work paper WPC-1a, p. 1). ComEd then made further adjustments that reduced its A&G expenses in its revenue requirement.

According to ComEd, its final revised revenue requirement includes $260,909,000 of A&G expenses for Illinois-jurisdictional delivery services (not including transmission service), a decrease of $8,920,000 from its original ***215** proposed figure of $269,829,000 due to adjustments made in its rebuttal and surrebuttal testimony. (*E.g.*, ComEd Ex. 5.1, Sched. C-1 Errata; Hill Sur., ComEd Ex. 36.0 Corr., Sched. 1 Rev., page 1).

According to ComEd, under the FERC's Uniform System of Accounts (the USOA), A&G expenses are recorded in Accounts 920-935. (*E.g.*, Hill Dir., ComEd Ex. 5.0 Corr., 26:549-50). Mr. Hill testified that 'costs included in those Accounts generally represent corporate support and overhead costs that benefit or derive from more than one operating business unit. Major A&G expenses support areas include Human Resources, Finance, Legal, Supply Management, and Information Technology departments. Additionally, the costs of employee pensions and benefits, including health care, are included in these A&G Accounts.'(*Id.* at 26:550-55). ComEd states that in general, the services, the costs of which are included in A&G expenses, are provided either internally, by ComEd employees or by other service providers, including Exelon's Business Services Company ('BSC').(*Id.* at 26:557-27:574).

****52** ComEd states that the $260,909,000 of A&G expenses that are included in its final revised revenue requirement are prudent, reasonable, necessary, and useful in performing the distribution and customer functions. (*E.g.*, Costello Dir., ComEd Ex. 3.0 Corr., 30:647- 31:675; Hill Dir., ComEd Ex. 5.0 Corr., 25:547-28:594; ComEd Ex. 5.1, Sched. C-1, C-2.1, C-2.2., C-2.3, C-2.4, C-2.8, C-2.11; ComEd Ex. 5.2, work papers WPC-1a, WPC-1b, WPC-2.1 Errata, WPC-2.2, WPC-2.5, WPC-2.8, WPC-2.11; Costello Reb., ComEd Ex. 13.0 Corr., 4:64-71, 31:696-34:763; Houtsma Reb., ComEd Ex. 18.0 Corr., 3:46-50, 5:90-7:142, 10:217-15:333; Hill. Reb., ComEd Ex. 19.0 Corr., 40:831 44: 929, Scheds. 1, 12, 13, 14, and 15; Costello Sur., ComEd Ex. 30.0, 1:21-25, 14:290-19:373; Houtsma Sur., ComEd Ex. 35.0, 2:25-42, 3:64-14:307; Hill Sur., ComEd Ex. 36.0 Corr., 34:772-38:855, Sched. 1 Rev., pp. 1-3, and Scheds 4 and 9).

Staff and intervenors have proposed numerous adjustments to ComEd's A&G expenses. In ComEd's opinion, ComEd's figure of $260,909,000 reflects that ComEd has accepted certain of their proposed adjustments, in some cases to narrow the issues. According to ComEd, Staff's and intervenors' remaining proposed adjustments to ComEd's A&G expenses lack merit and should not be approved. They are not supported by, and instead are contrary to, the evidence. They would deny ComEd recovery of prudent, reasonable, and necessary actual expenses incurred in order to perform the distribution and customer functions.

a.) Overall Amount

ComEd

In ComEd's opinions, the $260,909,000 of A&G expenses that are included in its final revised revenue requirement are prudent, reasonable, necessary, and useful in performing the distribution and customer functions, as referenced above.

ComEd states that none of Staff's and the IIEC's claims here have merit, for a host of reasons. First, ComEd avers that the record shows that $260,909,000 of its A&G expenses belong in its revenue requirement and Staff's and the IIEC's claims to the effect that ComEd has not met its burden of proof are incorrect in the face of that evidence. According to ComEd, neither Staff nor the IIEC have refuted that evidence. They have not shown that any of that $260,909,00 of A&G expenses is anything but prudent, reasonable, necessary, and useful in performing the distribution and customer functions. ComEd opines that while Staff has challenged certain of those expenses, those challenges all lack any merit. Moreover, ComEd argues that even if any of Staff's specific proposed adjustments to any particular A&G expenses had any merit, that would not warrant capping all A&G expenses arbitrarily as Staff has proposed. ComEd responded to the IIEC's arguments noting that the IIEC has not challenged any specific A&G expenses.

ComEd opines that the comparisons of total A&G levels in ICC Docket 01-0423, which involved a 2000 test year, and this Docket, which involves a 2004 test year, are ***216** inappropriate, misguided, and incomplete, if not misleading. According to ComEd, the record contains numerous uncontested facts refuting Staff's and the IIEC's positions. ComEd states:

****53** (1) ComEd's actual total 2004 A&G expenses are $123 million lower or 26% less than its actual total 2000 A&G expenses;

(2) in 2000, ComEd still was a vertically-integrated utility that owned generation assets, and if one removes the A&G expenses that were functionalized to the production function in ICC Docket 01-0423, then ComEd's non-production A&G expenses have increased by only 9.4% from 2000 to 2004 (less than the general inflation rate, as noted below);

(3) that 9.4% figure compares favorably to the 31% average increase and the 11.3% weighted average increase of the 178 electric utilities that filed FERC Form 1's for those years;

(4) ComEd's A&G expenses functionalized to the distribution and customer functions have increased only 14.2% from the level determined by ComEd's direct assignment study that was approved in ICC Docket 01-0423;

(5) the remainder of the difference from the prior Docket to this Docket is attributable to fact-based adjustments made in the prior Docket, with such difference a

reconciling factor, not a reason to challenge the level in this Docket;

(6) Staff and the IIEC ignore general inflation, which was 9.7% from 2000 to 2004;

(7) Staff and the IIEC ignore salary and wage increases, in particular, which have averaged approximately 3% per year; and

(8) there are A&G expenses that existed in 2004 that did not exist in 2000, including post-September 11th security expenses and Sarbanes-Oxley Act compliance expenses.

(Hill Reb., ComEd Ex. 19.0 Corr., 40:831- 43:900 and Scheds. 12, 13, 14, and 15).

According to ComEd, Staff's witness responded to only the fourth, fifth, seventh, and eighth of those eight points, and the responses lack merit. (*See* Lazare Reb., Staff Ex. 17.0 Corr., 15:363-18:449; Hill Sur., ComEd Ex. 36.0 Corr., 34:772-35:782, 35:786-36:804 and Sched. 9).

In ComEd's opinion, the Commission should reject Staff's and IIEC's position because Staff and the IIEC place no weight on the fact that in ICC Docket 01-0423 itself, the Commission approved an increase of these expenses of $48,807,000 or 38.2% from the level approved by the Order on Rehearing in ComEd's first delivery services rate case, ICC Docket 99-0117 (which used a 1997 test year). More recently, in *Northern Illinois Gas Company*, ICC Docket 04-0779 (Order *September* 20, 1995), the Commission approved a forecasted 2005 test year level of A&G expenses that was 97% higher that the 2001 actual level. Hill Reb., ComEd Ex. 19.0 Corr., 41:866-69.

ComEd argues that Staff's and the IIEC's claims are unreasonable on their faces in light of the adjustments already made by ComEd, and the amount already functionalized to the transmission function. ComEd states that Staff and the IIEC suggest that only $176,684,000 (Staff) or $155,300,000 (IIEC) of that $260,909,000 of actual A&G expenses should be included in the revenue *requirement*. Thus, Staff's and the IIEC's proposals necessarily suggest that, on top of the $34,767,000 already functionalized to the transmission function, there is another $84,225,000 (Staff) or $105,609,000 (IIEC) that: (1) supports the transmission function; or (2) supports no function. According to ComEd, that, however, is incorrect. The specific evidence regarding ComEd's A&G expenses is to the contrary.

****54** ComEd further argues that, Staff and the IIEC's supposition that A&G expenses should be more directly correlated to distribution O&M, customer accounts, and customer service information expenses, they are *actually* independent and it is incorrect to expect such a correlation. (*E.g.*, Costello Reb., ComEd Ex. 13.0 Corr., 4:68-69, 32:716-33:740; Hill Reb., ComEd Ex. 19.0 Corr., 43:901-09; Costello Sur., ComEd Ex. 30.0, 15:306-18). ComEd points to Mr. Chalfant's testimony to support its ***217** contention that IIEC's analysis and proposal are superficial and lack merit. (Tr. at 1663:16-1664:3, 1664:16-1665:6, 1665:11-14, 1688:2- 1690:13, 1691:6-1695:19, 1702:3-11; ComEd Cross Exs. 10, 13).

ComEd maintains that Staff's comments regarding the relative level of A&G expenses to O&M expenses has no supporting factual basis in the record to establish that ComEd's ratio is high. ComEd states that the record establishes that ComEd's ratio of A&G expenses to those other expenses is below average compared to peer utilities. (Costello Sur., ComEd Ex. 30.0, 15:319-17:331).

ComEd asserts that ComEd's costs for corporate governance and other services provided by Exelon BSC, in particular, which make up 47% of ComEd's actual total 2004 A&G expenses, as noted earlier, are prudent, reasonable, necessary, and useful in performing the distribution and customer functions, and the increase in these expenses from BSC's creation to 2004.

In ComEd's opinion, Staff's argument that it is recommending a level of A&G expenses higher than that set using the general labor allocator in the Commission's Interim Order in ICC Docket 01-0423, is that ComEd established that that is irrelevant and inconsistent with Staff's position on the subject of General Plant and Intangible Plant, where using the general labor allocator would increase the levels of General Plant and Intangible Plant in rate base.

Finally, ComEd asserts that the proposal that the Commission' reduce ComEd's A&G expenses based not on the evidence but on the Order in ICC Docket 01-0423 would be contrary to law.*E.g.* , 220 ILCS 5/10-113, 10-201(e)(iv).

Staff

Staff recommends that the overall amount of A&G not be adjusted from the last delivery services rate case. Adoption of Staff's recommendation would result in a $97.3 million decrease to the revenue requirement ComEd proposes in this docket. (Staff Ex. 6.0 Corrected, p. 33). Staff contends that ComEd's has not justified its requested increase.

According to Staff, ComEd provides five reasons why it's proposed A&G expenses are reasonable: (1) A&G costs have gone down; (2) functional structure; (3) general inflation; (4) general wage increases; and (5) *pro forma* adjustments. (ComEd Ex. 19.0 Revised, p. 38) ComEd's discussion of A&G expenses fails to get to the question at hand, which is, what is the basis for seeking such a large increase in this category of costs.

ComEd witness Hill argues that ComEd's proposed A&G expenses are reasonable because they are actually $123 million lower than total Company A&G expenses for the year 2000. Staff states that Mr. Hill's comparison is flawed. A&G expenses in 2000 included generation, whereas today ComEd no longer has generation. Therefore, the 2000 amount Hill relies upon is inflated and is akin to comparing apples to oranges.

****55** According to Staff, since ComEd only owns transmission and distribution, the more insightful comparison is the change in the level of A&G expenses for delivery services. Based on that comparison, ComEd's proposed increase is quite significant - 55% over the level approved for the 2000 test year. Staff states that the 2000 test year figure was based upon a functionalization methodology proposed by ComEd, rather than Staff or other intervenors. (Staff Ex. 17.0 Corrected, pp. 15-16).

Staff asserts that ComEd claims that its 2004 A&G costs have increased 9.4% since 2000, and that this percentage is well below other electric utilities. (ComEd Ex. 19.0 Revised, p. 39). Staff argues that this comparison is flawed on two counts. First, stating that its A&G expenses have increased 9.4% since 2000 is of no weight when its overall proposal is 55% greater than the total delivery services A&G expenses the Commission approved for the 2000 test year. The comparative figures for other utilities are irrelevant as well. Regardless of where ComEd stands relative to other utilities, the fact remains that it has failed to present any justification for its proposed increase in A&G expenses in this proceeding.

Staff argues ComEd's rationale related to ***218** general inflation and *pro forma* adjustments is equally non-plus. Staff maintains that these arguments are simply to 'make weight', and that the reality of the numbers presented by ComEd is that it is proposing a 55% increase over the level of A&G expenses the Commission found just and reasonable in Docket No. 01-0423.

According to Staff, ComEd witness Hill argues that A&G expenses must increase to accommodate general wage increases, which he claims to average approximately 3% per year since 2000, and that Staff's recommendation to 'freeze' the level of A&G expenses '…would deny all salaries and wage increases for the ComEd labor within the amount approved in Docket No. 01-0423.' (ComEd Ex. 19.0 Revised, p. 42). Staff avers that while ComEd may be paying its employees higher wages since 2000, its overall payroll costs have been decreasing since 2000 - according to FERC Form 1 data. The overall payroll costs in FERC Form 1 include direct distribution payroll, customer accounts and customer service payroll and A&G payroll. Direct distribution payroll declined from $189,664,419 in 2000 (2000 FERC Form 1, p. 354) to $118,128,755 in 2004 (2004 FERC Form 1, p. 354). Customer Accounts and Customer Service payroll costs also declined over that same period, from $89,914,798 and $4,513,156 in 2000 (2000 FERC Form 1, p. 354) to $77,745,065 and $1,888,017 in 2004 (2004 FERC Form 1, p. 354). Even A&G payroll costs declined by more than half between

2001 and 2004. (2001 FERC Form 1, p. 354, 2004 FERC Form 1, p. 354). Thus, ComEd has realized savings in overall labor costs, even with wages increasing between 2000 and 2004.

Staff relies on ComEd witness Landon's economies of scale argument:
Centralized provision of administrative services is an area that generally can be the source of large economies of scale and scope. I have seen no evidence that that is not the case here. Customers should pay their share of the costs that are incurred to serve them and from which they benefit.

****56** (ComEd Ex. 15.0, p. 12). Staff argues that ComEd witness Landon is referring to an opportunity by which ComEd should be realizing savings due to economies of scale, and that these savings should place downward pressure on A&G expenses.

Staff proposes that A&G expenses be set at $176,684,000. This results in a $97.3 million downward adjustment to ComEd's proposed revenue requirement. (Staff Ex. 6.0 Corrected, p. 33). In support of its position, Staff states that this is a healthy increase, of approximately 50%, over what was approved the last time a general labor allocator was used to set A&G expenses (*01-0423 Interim Order*). Second, Staff states that ComEd has not demonstrated that it warrants a greater increase. Third, Staff believes its proposed increase is a better proposal than ComEd's increase, because ComEd's A&G expenses are 132% above what was approved in the *01-0423 Interim Order*. Fourth, in Staff's opinion, increasing A&G costs is contradictory to the trend of declining direct expenses. Fifth, according to Staff, there is unnecessary uncertainty in ComEd's A&G expenses because costs caused by Exelon Business Services Company (‘BSC‘) cannot be reasonably reviewed or evaluated.

Staff contends that its proposed level of A&G expense is still significantly higher than levels approved by the Commission in other cases in which it approved of a general labor allocator. According to Staff, the Commission last adopted a proposed general labor allocator for A&G expense in its *01-0423 Interim Order*. The level of A&G expenses approved in that order was $118,153,000. (*01-0423 Interim Order*, Appendix A, Schedule 1). Staff compares its proposed A&G expenses in this docket to the A&G level approved in *01-0423 Interim Order* because ComEd is using a general labor allocator in this docket, similar to what the Commission approved in the *01-0423 Interim Order*. In contrast, the *01-0423 Order* used direct assignment. Staff avers that its proposal in this proceeding represents an increase of almost 50% over that figure.

Staff opines that ComEd's proposal amounts to an upward spiral in A&G expenses. ***219** The use, in the last rate case, of a direct assignment methodology rather than a general labor allocator methodology, dramatically increased ComEd's A&G expenses and set the table for the dramatic increase of 55% requested in this proceeding.

According to Staff, in ComEd's first DST rate case (Docket No. 99-0117), the Commission approved a total of $124,456,000 in A&G expenses based on the general labor allocator. (*Final Order*, Docket No. 99-0117, Appendix A, Schedule 1 (Aug. 26, 1999)). In ComEd's second delivery service rate case, Docket No. 01-0423, the Commission again adopted the general labor allocator for its Interim Order (dated April 1, 2002) and the result was a reduction in A&G expenses to $118,153,000. (*01-0423 Interim Order*, Appendix A, Schedule 1). When the Final Order in Docket No. 01-0423 accepted ComEd's direct assignment approach, the level of A&G expenses climbed sharply to $176,684,000. (*01-0423 Order*, Appendix A, Schedule 1). This represented an increase of $57,806,000 or 48.6% over the level approved in the *01-0423 Interim Order*. (Staff Ex. 6.0 Corrected, pp. 24-25).

****57** In this proceeding, Staff maintains, ComEd is using that as a staring point in an attempt to claim that its request in this case is reasonable. ComEd proposes A&G expenses for the 2004 test year of $274,013,000. (ComEd Ex. 5.0, Schedule A-5, p. 3 of 4). This represents an increase of $97,329,000, or 55.1%, over the level approved in the March 28, 2003 Order and $155,860,000, or 131.9% over the corresponding level set in the *01-0423 Interim Order*. (Staff Ex. 6.0 Corrected, p. 25).

Staff argues that ComEd's increase in A&G expenses is unjustified because it is clearly out of line with what is happening with other costs of ComEd. While ComEd's proposed A&G expenses are spiraling upwards, its proposed changes in direct expenses are declining. ComEd is proposing an increase of $97,329,000 in A&G expenses, while it is proposing a net reduction of $46,033,000 in the total of Distribution, Customer Accounts and Customer Service and Information expenses from the levels approved in the *01-0423 Order*. These figures would suggest that direct and indirect expenses are headed in opposite directions. (Staff Ex. 6.0 Corrected, p. 26). Staff asserts this is relevant because the Company itself proposes that A&G expenses be functionalized on the basis of a labor allocator in this proceeding (albeit a narrow allocator limited to transmission and distribution only). Staff further contends that the fact that proposed A&G expenses are bucking the trend of declining direct costs suggests that the success ComEd is realizing in controlling direct expenses is not carrying over to A&G expenses. Furthermore, Staff asserts, ComEd fails to offer any insight about why A&G expenses are lagging behind. (Staff Ex. 6.0 Corrected, p. 27).

Staff contends that ComEd witness Costello's claims that '…the fact that we have been successful in some areas does not imply that increases in other areas must be unreasonable' (ComEd Ex. 13.0 Corrected, p. 32) fails to address the real issue. Staff maintains that Costello fails to explain the distinguishing characteristic of A&G expenses that would make them increase when other costs are declining. Furthermore, he fails to provide any corroborating evidence to support his contention that A&G expenses are more difficult to control than other costs. (Staff Ex. 17.0 Corrected, p. 23).

According to Staff, BSC was created in 2001 for the purpose of providing support services that are common to multiple Exelon affiliate companies. Specifically, BSC provides information technology support, human resource support, finance support, legal support, communications support, executive management support and corporate governance support. (ComEd Ex. 5.0 Corrected, p 26). BSC has come to play a key role in the performance of the A&G functions, and accounts for 47% of unadjusted A&G expenses for the test year. (ComEd Ex. 5.0, p. 27).

Staff has two serious concerns about BSC, which, given that it accounts for 47% of unadjusted A&G expenses, has a tremendously significant impact on A&G expenses in the test year. ComEd claims that BSC provides efficiencies and cost savings that are passed along to ***220** Company. Staff contends that the A&G expenses proposed by ComEd, do not reflect these cost savings. Given that BSC accounts for a significant portion of A&G expenses, Staff posits that there should be some evidence of a reduction in A&G expenses.

****58** In addition, Staff has serious questions about difficulties in reviewing and evaluating the reasonableness of the costs attributed to BSC. These concerns about BSC create serious doubt and uncertainty about ComEd's proposed increase in A&G expenses. ComEd witness Heintz states that the complexity of ComEd's direct assignment approach for A&G expenses prevents ComEd from employing the direct assignment approach used in ComEd's last delivery service rate case, Docket No. 01-0423.He explains the problem as follows:

Notwithstanding ComEd's preference for functionalizing A&G expenses by direct assignment (as authorized by the ICC in its final order in Docket No. 01-0423), the information is no longer available to perform an accurate direct assignment. The reason is that, subsequent to the last distribution services general rate proceeding, ComEd has re-organized, and many administrative functions formerly performed within ComEd are now performed by Exelon Corporation's wholly-owned subsidiary, Exelon Business Services Company ('BSC '). Expenses for performing these functions are billed by BSC to ComEd and they are recorded in Account 923 - Outside Services Employed. Because the BSC bills are all recorded in a single account, it is impractical to perform the detailed analyses that are necessary to support a direct assignment methodology for A&G expenses.

(ComEd Ex. 11, pp. 17-18).

According to Staff, this statement raises fundamental questions about the transparency and quality of ComEd's functional allocation of A&G expenses and whether the reasonableness of these costs can readily be reviewed and evaluated. (Staff Ex. 17.0 Corrected, p. 26).

In its Reply Brief, Staff responded to several points ComEd made in its initial brief. Staff asserts that the evidence ComEd has provided in its initial brief to support its proposal as prudent, reasonable, necessary and useful (ComEd Init. Br., p. 92) is lacking. In addition to arguments Staff addressed in its initial brief, ComEd mentions that its A&G costs were affected by post-September 11th security and Sarbanes-Oxley costs. (*Id.*). Staff responds that ComEd has not provided any figures to demonstrate the effects of these expenses.

According to Staff, ComEd also attempts to justify its increase by comparing its request to the 97% increase NIGAS received in its most recent rate case. (ComEd Init. Br., p. 93). Staff responds that such a comparison is hardly worthy of weight, given that ComEd is an electric utility and NIGAS is a gas utility, and there is no evidence in this case demonstrating that the increase in NIGAS' A&G expenses is in any way similar to ComEd's situation.

According to Staff, the Company goes on to argue that Staff proposes to remove $84,225,000 from A&G expenses, and also characterizes Staff's adjustment as being either allocated to the transmission function or to no function. (ComEd Init. Br., p. 93). Staff posits that ComEd has failed to establish whether any of the numbers identified in its Initial Brief are meaningful for purposes of determining A&G expenses in this case; these numbers are stated but no citation to evidence is provided. Staff states that this top-down approach should be rejected, because it is contrary to the burden of proof established in Section 9-201(c) of the PUA. (220 ILCS 5/9-201(c) (stating that the utility has the burden of proving its requested rate)).

****59** Thus, Staff recommends the Commission find that ComEd has not supported its $84.225 million increase. Staff avers that $172,684,000 is a just and reasonable level of A&G expense. Finally, Staff points out that this adjustment is separate from what Staff witnesses Hathhorn and Ebrey are proposing for MGP expense, interest on customer deposits, incentive compensation expense, rate case expense, procurement case expense, charitable contributions, affiliate allocation and corporate governance ***221** costs as part of these adjustments' impact to A&G expense.

Commission Analysis and Conclusion

ComEd proposes an overall amount of $260,909,000 million to be included in its revenue requirement for administrative and general expenses. Staff proposes that the Commission cap the overall amount at the level approved in the 2001 delivery services docket, resulting in an overall amount of $176,684,000 million. Both parties present extensive arguments as to why their positions are correct. ComEd criticizes Staff for not evaluating ComEd's individual expenses. Staff criticizes ComEd for failing to provide enough information about individual expenses, even after Staff asked for such information. ComEd attributes a large percentage of its requested increase to the centralization of certain A&G expenses at BSC. Staff questions the amount attributable to BSC as being too high an inexplicable given that the idea behind BSC was to decrease expenses for centralized services.

The Commission does not find either party's position overly persuasive. ComEd, the party charged with proving its expenses are just and reasonable, provided us with the overall amounts contained in the Accounts related to A&G expenses and demonstrated in the aggregate how much its A&G expenses increased since the last rate case. However, ComEd failed to explain what the individual increases entailed. Moreover, conspicuously absent is a discussion about how ComEd's proposed increase to overall A&G expense is reasonable. The Commission cannot properly evaluate ComEd's request without being able to see the individual expenses contained in the A&G accounts and the rationale for any increases.

Staff's proposal to limit overall A&G expenses to the amount approved by the Commission in Docket No.

01-0423 is similarly problematic. Adopting such an approach also precludes the Commission from evaluating the reasonableness of individual A&G expenses. This could also cause ComEd to under-recover its expenses, leaving it in an untenable financial position. However, given the speculative nature of ComEd's proposed overall A&G expense amount, the Commission finds Staff's proposal to be a more appropriate starting point. Record evidence makes clear ComEd's A&G expenses increased between 2001 and 2004, so it would be inequitable to completely disallow any increase. Moreover, the record indicates an increase in the inflation rate of 9.7%. The Commission finds that Staff's proposal to cap overall A&G expenses at $176,684,000 million taking inflation into account to be reasonable. This results in an overall amount of $193,822,348 million. The Commission also notes that several individual expenses are discussed later in this Order. The overall amount of A&G expenses included in Appendix A reflects any adjustments to those sections as well.

b.) FunctionalizationComEd

****60** According to ComEd, its actual 2004 A&G expenses were $347,636,000. (*E.g.*, ComEd Ex. 5.2, at workpaper WPC-1a, p. 1). ComEd made adjustments that removed $25,727,000 of its actual 2004 A&G expenses, including $17,658,000 of executive compensation expenses, from its *calculations*, yielding a figure of $321,909,000, before functionalization. (*E.g.*, Hill Dir., ComEd Ex. 5.0 Corr., 27:575-86; ComEd Ex. 5.2, work paper WPC- 1a, pp. 1-3).

ComEd then functionalized that $321,909,000 of A&G expenses, using the general labor allocator based on the 2004 test year, determining that the amount that supported the distribution and customer functions was $287,142,000 and the amount that supported the transmission function was $34,767,000. [FN10] (Hill Dir., ComEd Ex. 5.0 Corr., 27:582-28:594; ComEd Ex. 5.1, Sched. C-1 Errata; ComEd Ex. 5.2, work paper WPC-1a, p. 1). ComEd posits that although A&G expenses should be directly assigned when feasible, it was not feasible in this case, and, therefore, ComEd used the general labor allocator because it was the best ***222** available method. (Hill Dir., ComEd Ex. 5.0 Corr., 27:587-28:593; ComEd Ex. 5.2 work papers WPA-5, p. 1. (calculation of the general labor allocator based on the 2004 test year) and WPC-1a, p. 1). ComEd states that its allocation of all of those expenses between the distribution, customer, and transmission functions makes sense. ComEd is ‘just a T&D utility‘ now, as Staff's witness testified. (Lazare, Tr. at 643:12-13). The last time that ComEd had significant production capital costs or production operating expenses, not including purchased power expenses, was 2001, as he also testified. (*Id.* at 632:11-17). That leaves ComEd with only one function besides the distribution and customer functions-transmission. (*See id.* at 612:18-613:12 (discussing the four functions: production, transmission, distribution, and customer)).

ComEd asserts that the $260,909,000 of A&G expenses that are included in its final revised revenue requirement are prudent, reasonable, necessary, and useful in performing the distribution and customer functions. (*E.g.*, Costello Dir., ComEd Ex. 3.0 Corr., 30:647-31:675; Hill Dir., ComEd Ex. 5.0 Corr., 25:547-28:594; ComEd Ex. 5.1, Sched. C-1, C-2.1, C-2.2., C-2.3, C-2.4, C-2.8, C-2.11; ComEd Ex. 5.2, work papers WPC-1a, WPC-1b, WPC-2.1 Errata, WPC-2.2, WPC-2.5, WPC-2.8, WPC-2.11; Costello Reb., ComEd Ex. 13.0 Corr., 4:64-71, 31:696-34:763; Houtsma Reb., ComEd Ex. 18.0 Corr., 3:46-50, 5:90-7:142, 10:217-15:333; Hill. Reb., ComEd Ex. 19.0 Corr., 40:831 44: 929, Scheds. 1, 12, 13, 14, and 15; Costello Sur., ComEd Ex. 30.0, 1:21-25, 14:290-19:373; Houtsma Sur., ComEd Ex. 35.0, 2:25-42, 3:64-14:307; Hill. Sur., ComEd Ex. 36.0 Corr., 34:772-38:855, Sched. 1 Rev., pp. 1-3, and Scheds 4 and 9).

ComEd opines that its functionalization of its A&G expenses should be approved. According to ComEd, the evidence shows that use of the general labor allocator is appropriate in this case. No party disputes that ComEd calculation of the general labor allocator based on the 2004 test year is correct. ComEd opines that no party has shown any valid reason to reject ComEd's functionalization. No party has proposed any other method to functionalize ComEd's A&G expenses.

****61** According to ComEd, Staff does not claim to have shown any error in ComEd's functionalization of its A&G expenses. Staff does not propose any method of functionalizing ComEd's A&G expenses, and instead rests on its proposal to cap these expenses at the level of $176,684,000 approved in ICC Docket 01 0423 (which involved a 2000 test year). (*E.g.*, Lazare, Tr. at 638:2-11; Lazare Dir., Staff Ex. 6.0 Corr., 20:483 - 21:507). In ComEd's opinion, even though Staff's adjustment is based on the amount approved for the 2000 test year, Staff has had to acknowledge that ComEd is not the same utility now, as noted earlier. ComEd asserts that Staff's witness also has stated that: ‘The utility, as it exists today is quite different from the utility that exists in those three cases [ICC Dockets 98-0680, 99-0117, and 01-0423]. The calculations that I wish to perform that I performed in the previous incarnation of the utility are no longer possible for just a T&D utility which ComEd is now.‘ (Lazare, Tr. at 643:7-13). The uncontradicted fact, however, is that the general labor allocator calculation has been performed, and used, by ComEd to functionalize its A&G expenses in this Docket.

ComEd states that Staff's remaining asserted concerns on this subject have no merit. In ComEd's opinion, Staff claims that the increase from the level of A&G expenses approved in ICC Docket 01-0423, $176,684,000, to the level included in ComEd's proposed revenue requirement in the instant case somehow casts doubt on ComEd's functionalization of its A&G expenses (*e.g.*, Lazare Dir., Staff Ex. 6.0 Corr., 20:483-21:507, 25:625-34, 27:670-75), but Staff's asserted concerns about the increase are shown to be without merit for the reasons given by ComEd that are referenced in the next subsection of this Order. According to ComEd, Staff also expresses concern about the relative changes in ComEd's A&G expenses versus its distribution O&M, customer accounts, and customer service and information expenses (*e.g.*, Lazare Dir., Staff Ex. 6.0 Corr., 26:636-27:675), but Staff's asserted concerns about those relative changes ***223** also are shown to be without merit for the reasons given by ComEd that are referenced in that section. Finally, ComEd maintains, Staff also claims that ComEd's restructuring, in particular, the creation of BSC, and the allocation of corporate governance and other expenses for which ComEd is charged by BSC complicate the assessment of ComEd's A&G expenses (*e.g.*, Lazare Dir., Staff Ex. 6.0 Corr., 21:519-22:527), but ComEd believes Staff's asserted concerns on those subjects are without merit. ComEd asserts that Staff has overstated the effect of its proposed cap on A&G expenses. ComEd posits that Staff, in its briefing, failed to correctly update its figure for the incremental impact on ComEd's A&G expenses of the proposed cap in light of adjustments made by ComEd that reduced its request, which led to Staff proposing that ComEd only be allowed $172,500,000 of A&G expenses, rather than $176,684,000. (Staff Init. Br., App. A, Schedule 1, line 11 and Schedule 2, page 3, line 11, column (w)).

****62** ComEd also states that no intervenor has provided any grounds for rejecting ComEd's functionalization of its A&G expenses. The IIEC submitted direct testimony questioning the increase from the level of A&G expenses approved in ICC Docket 01-0423 to the level included in ComEd's proposed revenue requirement in the instant case, and proposing that the level be tied to the percentage decrease in the sum of ComEd's distribution O&M, customer accounts, and customer service and information expenses. (Chalfant Dir., IIEC Ex. 2.0, 2:18-22, 2:35-6:109). According to ComEd, after ComEd refuted the IIEC's testimony on this subject, the IIEC did not even offer any rebuttal testimony on this subject. The IIEC's witness did not directly address the subject of functionalization of ComEd's A&G expenses, and he provided no direct or indirect grounds for rejecting ComEd's functionalization.

ComEd maintains that CES' rebuttal testimony suggesting that Staff's witness in his direct testimony ‘makes the same point with respect to Administrative and General Expenses ('A&G’) as he did with respect to G&I plant ‘ (O'Connor/Domagalski Reb., CES Ex. 5.0, 9:179-81) is incorrect in three different ways. First, ComEd highlights that Staff's witness made no such claim. Second, ComEd notes that A&G expenses are operating expenses. ComEd states that the A&G expenses at issue in ICC Docket 01-0423 were the actual

A&G expenses of ComEd's 2000 test year, while the A&G expenses at issue in this Docket are ComEd's actual A&G expenses of the 2004 test year, four years later. (*E.g.*, Lazare, Tr. at 655:20-656:13). According to ComEd, the A&G expenses of 2000 are not part of the revenue requirement in this Docket, and the A&G expenses of 2004 have never before been functionalized and there has been no shifting of expenses.

IIEC

IIEC takes the position that A&G expenses are principally related to the corporate activities of the utility, such as salaries of corporate officials, pensions and benefits, injuries and damages, office supplies and miscellaneous expenses. Such expenses are sometimes referred to as ‘overhead.‘ IIEC says ComEd proposes to reflect $274 million of these overhead expenses in its delivery service rates. This increase in overhead represents an increase of $97.3 million or 55% over the levels authorized in the Company's last rate case. This represents over one-quarter of the total increase requested by ComEd in this proceeding.

IIEC recommends a level of A&G expense based on the percentage increase or decrease in O&M expense, other than A&G, ultimately approved in this case. It is IIEC's position that this would maintain the relationship between overhead and O&M expenses that resulted from the Commission's rate order in ComEd's last delivery service rate case. Under this approach, if ComEd's requested level of O&M, other than A&G, is adopted in this proceeding, ComEd would require a level of overhead expense in this case of $155.4 million. This would reduce ComEd's revenue requirement by approximately $119 million according to IIEC.

****63** IIEC says its recommendation should be adopted for several reasons. First, in the last rate case, both Staff and IIEC recommended the Commission reduce ComEd's A&G expense for ***224** the delivery service function. IIEC notes the Commission specifically approved $176.7 million as the reasonable A&G level for ComEd's 2000 test year. In the last case, the Commission also determined that ComEd's O&M expense (other than A&G) for the 2000 test year should be $493.7 million. Therefore, IIEC reasons the Commission's Order in the last case had the net effect of approving 35.8 cents of A&G, or overhead expense, for every dollar of O&M expense other than A&G. IIEC states ComEd has provided no rationale or justification for an increase in its overhead expenses to 63.2 cents per dollar of O&M, other than A&G. IIEC says its proposal maintains the relationship between A&G and O&M, other than A&G, established in the last case.

IIEC next says ComEd did not compare its proposed level of A&G to past levels of A&G and did not compare its proposed level of A&G to the level of O&M it is requesting in this case. IIEC reasons that ComEd, not intervenors, has the burden to prove the justness and reasonableness of its rates. In failing to compare levels of A&G in this case with the A&G levels in the last case, and failing to compare the level of A&G requested in this case to the level of O&M, other than A&G, requested in this case, ComEd has failed to meet its burden.

Therefore, IIEC concludes that to the extent the Commission approves an increase or decrease in the level of O&M, other than A&G, needed for delivery service in this case, the level of A&G or overhead expense should be increased or decreased proportionately. IIEC says this will maintain the relationship of 35.8 cents of overhead for every dollar of O&M, other than A&G, that exists in current rates.

CES

CES recognizes that Staff makes the same point with respect to A&G that was made with respect to G&I plant. That is, according to the Coalition, A&G previously allocated to supply has now been shifted to delivery service by ComEd, without an adequate explanation of the service being provided. (*See* Staff Ex. 6.0 at lines 454-514). CES argues that to the extent the Commission finds A&G expenses that ComEd has improperly allocated to delivery services that are more properly related to supply-related services, then the appropriate method of collection is through the SAC. (*See* CES Ex. 5.0 at lines 171-86; CES Init. Br. at 20).

Commission Analysis and Conclusion

ComEd argues that its functionalization of its A&G expenses should be approved. The evidence shows that use of the general labor allocator is appropriate in this case given the available information. There is no dispute that ComEd calculation of the general labor allocator based on the 2004 test year is correct. No party has proposed any other method to functionalize ComEd's A&G expenses or shown any valid reason to reject ComEd functionalization. Staff does not propose any other method of functionalizing ComEd's A&G expenses, but instead rests on its proposal to cap these expenses at the level approved in ICC Docket 01-0423.Staff's proposed cap is $176,684,000, the amount approved for the 2000 test year. However, both ComEd and Staff acknowledge that ComEd is not the same utility that was in 2000 and has not been for over five years. Staff's proposal to cap A&G expenses is without merit and is rejected.

****64** CES requested that, the Commission review ComEd's A&G expenses to determine whether it included any expenses that are not properly allocated to the distribution and customer functions. If the Commission determines that any expenses are more properly allocated to the production function, then CES proposes that those expenses be recovered through a Supply Administration Charge. CES does not specifically address any expenses that it feels should be allocated to the production function. The Commission did not find any expenses that should be recovered though a Supply Administration Charge. No other intervenor provided any grounds for rejecting ComEd's functionalization of its A&G expenses. IIEC's witness did not directly address the subject of functionalization of ComEd's A&G expenses. Therefore, the Commission finds that ComEd's functionalization***225** of its A&G expenses is reasonable and is approved.

c.) Corporate Governance Expenses

ComEd

[33, 34] ComEd seeks recovery of $49,867,000 in jurisdictional corporate governance expenses paid by ComEd to Exelon BSC in the 2004 test year. ComEd states that corporate governance services are provided to ComEd by Exelon Business Services Company (‘BSC‘) under the terms of the General Services Agreement (‘GSA‘) approved by the ICC and the Securities and Exchange Commission (‘SEC‘). (Hill Dir., ComEd Ex. 5.0 Corr., 26:561-69). According to ComEd, the record shows that costs for these services are directly charged to ComEd where possible, and if costs cannot be direct charged, they are allocated to ComEd and the other Exelon affiliates using an allocation factor reflecting cost connection. (Hill Dir., ComEd Ex. 5.0 Corr., 26:569- 27:573).

According to ComEd, the factor used to allocate corporate governance costs is called the Modified Massachusetts Formula, or MMF. ComEd and Exelon were required to use the MMF for corporate governance costs by the SEC starting in 2004. (Hathhorn Dir., Staff Ex. 1.0, 11:224-12:234; Hathhorn, Tr. at 1736:14-1737:7). The MMF uses three factors as inputs to its allocation formula - gross revenues, total assets, and direct labor. (Hathhorn Dir., Staff Ex. 1.0, 9:177-79). ComEd states projected ComEd values for gross revenues and direct labor and an actual ComEd value for assets from near the end of the calendar year (here, 2003) were used as data inputs into the MMF to calculate the corporate governance allocation factor for the following year (here, 2004). (Hathhorn, Tr. at 1737:8-1738:21).

ComEd maintains that despite Staff's arguments, the reasons for use of projected values are straightforward. First, ComEd states that as services are rendered during the year (here 2004), the costs of these services must be allocated so that BSC can charge for the services. (Houtsma Sur., ComEd Ex. 35.0, 4:69-72; Hathhorn, Tr. at 1739:3-21). ComEd states that data which are only available after the close of the books in 2005 cannot be used to charge for services as they are rendered in 2004. Second, ComEd asserts that the actual data for use in the MMF for a given year - here 2004 - is not available even at the time the books are closed for a given year, and it would be very cumbersome and problematic if actual data were required to recompute all of the cost allocations. (Houtsma Sur., ComEd Ex. 35.0, 4:69-76).

****65** ComEd states that Staff does not challenge that the 2004 corporate governance costs in question were properly and accurately allocated under the MMF for 2004. (Hathhorn, Tr. at 1735:9-1737:9). Nor does Staff advocate or recommend a permanent change to ComEd's on-going allocation procedures. (Hathhorn, Tr. at 1738:15-21). ComEd avers that Staff's proposed adjustment violates test year principles. Furthermore, ComEd argues that Staff has submitted no evidence that its ‘for ratemaking purposes‘ methodology will be as accurate in predicting future corporate governance costs as the methodology used by ComEd - the same methodology that will be used for allocating costs and charging for services in those future years.

ComEd further posits that not only does Ms. Hathhorn's recommended disallowance violate test year principles, but at bottom her proposed disallowance does not rest on any finding that the corporate governance costs actually paid in 2004 are not just and reasonable. According to ComEd, Staff's analysis is in hindsight and is not a reasonableness test. ComEd disagrees with Staff's analysis for at least four reasons. First, Staff witness Ms. Hathhorn's testimony makes it completely clear that her recalculation of the MMF using actual 2004 inputs was separate from her analysis of indirect corporate governance costs charged to ComEd. Second, Ms. Hathhorn's discussion about indirect versus direct charges was never a basis for any recommended disallowance, and certainly was not the basis of her $663,000 disallowance. Third, the absence of any connection between Ms. Hathhorn's actual corporate governance***226** disallowance and her direct/indirect ratio analysis is further confirmed by the fact that although Ms. Hathhorn observes that the ratio of direct to indirect charges is different for Exelon's regulated utilities than for its unregulated businesses, she never testifies that they should move in tandem or specifies what an appropriate ratio would be. Fourth, and, had the difference in the ratios Ms. Hathhorn observes been used to calculate a disallowance, the disallowance would have been a vastly different number than the $663,000 disallowance she recommends. ComEd posits that if Staff believed that corporate governance costs were not being allocated fairly and equitably allocated among the Exelon family of companies, Staff would not have been justified in recommending that going forward, ComEd not change its procedures for allocating such costs. Finally, ComEd asserts that as further evidence that Staff's proposed $663,000 adjustment is unrelated to Staff's analysis of the ratio of direct to indirect corporate governance charges, that adjustment would have an immaterial impact on that ratio.

Contrary to Staff's assertions, ComEd states that the differences in the ratios are simply an indication that direct costs are being appropriately charged to the unregulated subsidiaries, as required by the GSA, and not an indication that cost allocations are not appropriate. (Houtsma Sur., ComEd Ex. 35.0, 4:86- 5:92). ComEd witness Ms. Houtsma testified that the amount of direct charges to a given business unit is a reflection of the level of services provided directly to that affiliate, and the volume of directly assigned services would not necessarily be expected to be proportionate among business units. In particular, Ms. Houtsma testified that the higher level of direct finance charges to Exelon Generation Company, LLC in 2004 are related to Exelon Generation's property insurance which has been appropriately directly charged to Exelon Generation rather than indirectly allocated among all business units. (Houtsma Sur., ComEd Ex. 35.0, 4:89-5:103).

Staff

****66** Staff witness Dianna Hathhorn proposed an adjustment of $663,000 in operating expenses to reduce ComEd's corporate governance charges from BSC. (Staff Ex. 1.0, pp. 8-12, Schedule 1.7). Ms. Hathhorn's adjustment calculates ComEd's corporate governance charges using the most recent actual 2004 values for the inputs to the formula used to allocate corporate governance charges, to better match the historical test year with actual 2004 activity. (Staff Ex. 1.0, p. 9). The Company used forecasted inputs prepared prior to the start of the year to calculate its allocation factors. (ComEd Ex. 18.0 Corrected, p. 5).

As set forth in Ms. Hathhorn's testimony, corporate governance costs are defined in Section 7 of ComEd's GSA, approved in Docket No. 00-0295 which was Attachment A to Staff Ex. 1.0. In the final GSA, which contains certain modifications by the SEC, corporate governance is defined as:

'…those activities and services reasonably determined to be necessary for the lawful and effective management of Exelon System business. Corporate Governance Services may be supplied from functions such as accounting, finance, executive, strategic planning, legal, human resources/benefits, audit, corporate communications and public affairs, environmental health and safety, government affairs and policy, and investor relations…'

Ms. Hathhorn testified that these costs are allocated from BSC to ComEd using the MMF, which uses gross revenues, total assets, and direct labor as inputs to the allocation formula. The MMF used for the test year was calculated based upon 2004 projected gross revenues and direct labor, and assets at their 9/30/2003 value. (Staff Ex. 1.0, p. 9).

Since 2004 was the first year the MMF was used to allocate ComEd's corporate governance charges, Ms. Hathhorn states that she conducted a reasonableness analysis based on the amounts of indirect corporate governance costs charged to ComEd versus its affiliates in 2004. (Tr., p. 1753). She testified that her analysis (*See* Staff Ex. 1.0, p. 11, Table 1) showed ***227** that ComEd and its regulated affiliate, PECO Energy Company ('PECO') received almost exactly the same ratio of direct to indirect corporate governance charges from BSC - 11% direct and 89% indirect. Further, she stated that her analysis showed that the two non-regulated affiliates of ComEd - Exelon Corporation ('Exelon'), and Exelon Generation Company LLC ('Genco') - received almost exactly the same ratio of direct to indirect corporate governance charges from BSC, 28% direct and 72% indirect. Therefore, Ms. Hathhorn concluded that when compared to the regulated affiliates, the non-regulated affiliates received much lower percentages of indirect corporate governance costs, which indicates that indirect corporate governance costs were not allocated fairly and equitably among the Exelon family of companies in 2004. (Staff Ex. 1.0, p. 11, Table 1).

Ms. Hathhorn espoused in her rebuttal testimony and at the hearings that her adjustment was solely for ratemaking purposes, and that Staff does not advocate a change to the amount recorded under the methodology approved in the GSA. (Staff Ex. 12.0, p. 6 and Tr., p. 1738). Staff noted in its Initial Brief that no one claimed that Staff's adjustment is inconsistent with the GSA. (Staff Init. Br., p. 50). Further, Staff contends that ComEd itself considered an adjustment to reflect the actual inputs in place of the estimated ones and the Commission often approves adjustments to test-years to change the amount actually recorded by a utility to a more appropriate amount for ratemaking purposes, such as average storm damage and tree trimming expense amounts. (*Id.*). Staff in its Initial Brief argues that (1) its adjustment from the amount actually recorded on the books of the utility to a proper test-year balance in no way violate test year principles, despite ComEd witness Houtsma claim in her testimony (ComEd Ex. 35.0, p. 2); (2) Ms. Houtsma contradicted herself at the evidentiary hearing; and (3) ComEd acknowledged that it has discretion under the GSA to adjust allocated amounts based on projections to using actual data (Tr., pp. 354, 454-456) but did not make the change because it was not material (Tr., pp. 360-361, 452) (*Id.*, pp. 50-51). Staff also argues in its Initial Brief that under the Act, amounts included in rates may be different than those calculated according to a Commission-approved affiliate interest allocation agreement, (*See* 220 ILCS 5/7-101(3)) given that Section 7-101(3) of the Act states that consent or approval of an affiliate interest agreement, such as the GSA, by the Commission does not constitute approval of payments thereunder for the purpose of computing expense of operation in any rate proceeding. (*Id.*, p. 51).

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****67** CCC concurs with Staff that corporate governance costs should be allocated based on actual cost information, rather than projected. Corporate governance costs are allocated using the MMF, which uses gross revenues, total assets, and direct labor as inputs to the allocation formula. (Staff Ex. 1.0 at 9, L. 177-179). ComEd calculated the test year MMF based upon 2004 projected gross revenues and direct labor, as well as assets at their September 30, 2003, value. CCC agrees with Staff witness Ms. Hathhorn's recommended adjustment to allocate the test year costs based on actual 2004 data, rather than projections. (*Id.* at 9, L. 182-184).

CCC asserts that ComEd witness, Ms. Houtsma, acknowledged on cross-examination that ComEd could - and does - conduct an after the fact calculation using actual data to develop the MMF allocators; it just chose not to do so for practical reasons. For purposes of exacting the most precise level of corporate governance charges to be collected from the regulated utility and charged to ratepayers, and to maintain compliance with the just and reasonable and known and measurable standards articulated in the Commission's rules, CCC propose that the Company regenerate the corporate governance allocators using the most recent actual 2004 values for these inputs, to better match the historical test year with actual 2004 activity. This would result in a $663,000 decrease to corporate governance charges included in ComEd's test year A&G expense.

***228** *Commission Analysis and Conclusion*

ComEd seeks recovery of $49,867,000 in jurisdictional corporate governance expenses paid by ComEd to Exelon BSC in the 2004 test year. ComEd explains that corporate governance services are provided to ComEd by BSC under the terms of the GSA approved by the ICC and the SEC. Section 7 of ComEd's GSA, defines as: '…those activities and services reasonably determined to be necessary for the lawful and effective management of Exelon System business. Corporate Governance Services may be supplied from functions such as accounting, finance, executive, strategic planning, legal, human resources/benefits, audit, corporate communications and public affairs, environmental health and safety, government affairs and policy, and investor relations…' Costs for these services are directly charged to ComEd where possible, and if costs cannot be direct charged, they are allocated to ComEd and the other Exelon affiliates using an allocation factor reflecting cost connection. Hill Dir., ComEd Ex. 5.0 Corr., 26:569-27:573.

ComEd and Exelon uses the MMF to allocate corporate governance costs. ComEd and Exelon were required to use the MMF for corporate governance costs by the SEC starting in 2004. The MMF uses three factors, gross revenues, total assets and direct labor, as inputs to its allocation formula. ComEd used projected values for gross revenues and direct labor and an actual value for assets from near the end of the calendar year 2003 and used them as data inputs into the MMF to calculate the corporate governance allocation factor for the year 2004.

****68** Staff proposes an adjustment of $663,000 in operating expenses to reduce ComEd's corporate governance charges from BSC to match the historical test year with actual 2004 activity. Staff's witness Ms. Hathhorn's adjusted ComEd's corporate governance charges using the most recent actual 2004 values for the inputs to the formula used to allocate corporate governance charges instead of using ComEd's forecasted inputs.

The Commission finds Staff's analysis persuasive. Since 2004 was the first year the MMF was used to allocate ComEd's corporate governance charges, Staff's reasonableness analysis based on the amounts of indirect corporate governance costs charged to ComEd versus its affiliates in 2004 makes sense. ComEd and its regulated affiliate, PECO, received almost exactly the same ratio of direct to indirect corporate governance charges from BSC - 11% direct and 89% indirect. The two non-regulated affiliates of ComEd - Exelon, and Genco - received almost exactly the same ratio of direct to indirect corporate governance charges from BSC, 28% direct and 72% indirect. The non-regulated affiliates received much lower percentages of indirect corporate governance costs. This indicates that indirect corporate governance costs were not allocated fairly and equitably among the Exelon family of companies in 2004.

The Commission accepts Staff's proposed adjustment ratemaking purposes, and does not intend a change in the amount recorded under the methodology approved in the GSA. No one claimed that Staff's adjustment is inconsistent with the GSA. Tellingly, ComEd itself considered an adjustment to reflect the actual inputs in place of the estimated ones and the Commission often approves adjustments to test-years to change the amount actually recorded by a utility to a more appropriate amount for ratemaking purposes. Additionally, under the PUA, amounts included in rates may be different than those calculated according to a Commission-approved affiliate interest allocation agreement, (*See* 220 ILCS 5/7-101(3Consent or approval of an affiliate interest agreement, such as the GSA, by the Commission does not constitute approval of all payments there under for the purpose of computing expense of operation in any rate proceeding.

In conclusion, the Commission agrees with Staff in making this adjustment based on actual costs. Therefore, Staff's proposed adjustment of $663,000 is approved.

d.) Exelon BSC Expenses

ComEd

[35, 36] ComEd proposed a revised figure of $143,392,000 in rebuttal testimony for ex- ***229** penses allocated to ComEd (and recorded in A&G Accounts 920, 921 and 923) for the provision by BSC of centralized services in the test year under the GSA. (Houtsma Reb., ComEd Ex. 18.0 Corr., Sched. 18.1).

Regarding Staff's revised $10 million adjustment to its proposal, ComEd states that Staff's revised four year normalization adjustment continues to be incorrect and misconceived by failing to account for increased costs due to centralization. ComEd posits that Staff's proposal is a normalization of the four year average of costs for centralized services provided by BSC. (Hathhorn Reb., Staff Ex. 12.0, 13:285-88). ComEd states, however, that normalization adjustments to actual test year expenses are not justified where they do not more accurately portray the reasonably expected level of costs over the period of time the rates set in this proceeding will be in effect. (*See,e.g.* , *Illinois Bell Telephone Company,* Docket No. 89-0033, 1992 Ill. PUC LEXIS 633, *95-96 (November 4, 1991); *Central Illinois Public Service Company d/b/a American CIPS and Union Electric Company d/b/a American UE,* 1999 Ill. PUC LEXIS 646, 16-17 (Ill. PUC 1999)). ComEd asserts that Staff's use of a four year average has exactly the opposite effect - it creates a wholly artificial number which the record in this case establishes beyond a doubt is not only well under the level of BSC expense actually experienced in the 2004 test year, but well under the level of BSC expense experienced in 2005 and expected to be experienced in subsequent years. In particular, ComEd states that Staff's proposal is inconsistent with and ignores changes made by ComEd on January 1, 2004, as part of the Exelon Way program.

****69** In 2003 and 2004 Exelon embarked on the Exelon Way, one aspect of which was to centralize and consolidate common functions throughout Exelon as a means to improve performance and achieve efficiencies. According to ComEd, no party disputes that as part of this reorganization, 436 employees who perform support functions such as information technology, finance, and engineering were transferred from ComEd to Exelon BSC as of January 1, 2004, resulting in Exelon Energy Delivery Shared Services ('EDSS') costs in the relevant BSC accounts that went from approximately $6.3 million in 2003 to $24.7 million in 2004. (Hathhorn, Tr. at 1746:4-9; Hathhorn Reb., Staff Ex. 12.0, Sched. 12.8, p. 2 of 2). ComEd asserts that the Exelon Way reorganization is at an end and therefore these employees are not going back. ComEd also asserts that the Exelon Way program was a significant reorganization and was done to achieve long-term sustainable savings, not just a one-year temporary reorganization.

Regarding Staff's argument that because Staff witness Ms. Hathhorn has included EDSS in her revised analysis, the impact of centralization has already been accounted for, ComEd states that this is incorrect and contrary to the record. ComEd states that EDSS costs included in Accounts 920, 921 and 923 increased by $18.4 million in 2004 compared to 2003. ComEd stresses that although Ms. Hathhorn's average includes EDSS, so did the test year amount to which she compares the average also includes EDSS; in fact the test year EDSS was higher then in prior years. (Houtsma Surr., ComEd Ex. 35.0, 7:151-8:155). ComEd opines that Ms. Hathhorn's averaging methodology results in a number of approximately $9 million which, when compared to the actual EDSS costs of approximately $24 million, is short by $15 million. (Hathhorn, Tr. at 1746:4-1748:6).

In regard to Staff's argument that it could not accurately analyze how the centralized expenses in 2004 compare to prior years, since the expenses were recorded in different accounts and at a different entity prior to 2004 (Hathhorn Dir., Staff Ex. 1.0, 16:329-32), ComEd contends that the record shows BSC costs went up in the test year by virtue of centralization, and that this centralization has led to overall cost savings. ComEd avers that, overall, the Exelon Way program reduced ComEd's 2004 O&M expense by $66 million ($59 million on a jurisdictional basis). (Houtsma Reb., ComEd Ex. 18.0 Corr., 13:270-80). ComEd states that this savings was achieved, in part, due to the greater reliance on shared services provided by Exelon BSC and the transfer of ***230** over 436 employees to Exelon BSC. (*Id.*). at 13:276-83.In addition, ComEd states that the fact that the costs are now recorded in different accounts is purely driven by the FERC Uniform System of Accounts, which provides for separate accounts for internally incurred payroll and service company billings. (*Id.*).

ComEd states and Ms. Hathhorn agreed, that the issue is whether on a going forward basis, the cost level for services provided by the EDSS department of BSC is more likely to be $9 million (the result of Ms. Hathhorn's four year 'normalization' through averaging) or approximately $24 million. (Hathhorn, Tr. at 1748:7-12; *see also* Hathhorn Reb., Staff Ex. 12.0, 15:323-25). ComEd opines that there is no record evidence, apart from the mathematics of averaging, supporting a conclusion that during the years rates established in this case will be in effect, the level of BSC costs for centralized services, and particularly EDSS services, will be anywhere close to $9 million. According to ComEd, it provided unrebutted evidence as to why the BSC costs increased and why the level of costs resulting from the reorganization will continue in future years, and provided unrebutted evidence that BSC costs in 2005, the year following the 2004 test year, were virtually the same as in 2004. Ms. Houtsma testified that '[i]n 2005, ComEd's total BSC charges were $256 million, almost identical to the $254 million in 2004.' (Houtsma Sur., ComEd Ex. 35.0, 8:171-72). According to ComEd, Ms. Hathhorn agreed that she had no reason to disbelieve these figures. (Tr. at 1750:10-20). Ms. Houtsma further testified that '[t]he portion of 2005 BSC costs recorded in Accounts 920,921 and 923 was $130 million, well in excess of the four year average of $104.9 million proposed by Ms. Hathhorn, which demonstrates that the test year amount is much more representative of amounts to be incurred prospectively than in a four-year average that includes the pre-Exelon Way organization.' (Houtsma Sur., ComEd Ex. 35.0, 8:172-77. Ms. Hathhorn also agreed that this comparison 'doesn't sound wrong.' Hathhorn, Tr. at 1751:5-6).

****70** ComEd states that although CCC proposed disallowances based on a normalization adjustment, those disallowances are misconceived and incorrect for much the same reasons as applied to Ms. Hathhorn's adjustments. ComEd asserts that even though his testimony is otherwise silent on this point, CCC Witness Mr. McGarry disallows costs related to the MMF. ComEd posits that the adoption of the MMF to allocate corporate governance costs was a change required by the SEC that will remain in effect for periods subsequent to the test year, and accordingly Mr. McGarry's proposed disallowance of these costs, without explanation, is ill-founded. (Houtsma Sur., ComEd Ex. 35.0, at 10:215-11:231).

Regarding CCC's second argument, that the increases in BSC costs allocated to ComEd as a result of the sale of Enterprises should not be allowed, ComEd states that the nature of indirect corporate governance costs is such that they do not necessarily change with the addition or sale of an affiliate; in other words, these are costs that do not vary in exact proportion to the overall size of the holding company system. ComEd states that although the allocation increased in the test year, the allocation of these costs to ComEd may increase or decrease based on the change in ComEd's size relative to the overall size of the holding company system.

In response to CCC witness Mr. McGarry's request for some form of an evaluation or audit of BSC costs, ComEd opines that the record is devoid of any evidence that the BSC costs are unreasonable. ComEd states that in fact the record already reflects the history of ComEd's total billings form BSC, broken down into three categories - corporate charges, transactional costs, and Energy Delivery Shared Services. According to ComEd, the record shows that the $119.7 million combined increase in the corporate governance charges and EDSS areas comprise the Exelon Way centralization ($98 million increase in total BSC costs), the sale of Enterprises ($13 million), and the adoption of the MMF ($12 million). The transactional costs, which are the services that are billed on a rate times volume pricing basis, have actually decreased from $85.4 million in 2001 to $84.3 million in 2004. (Houtsma Sur., ComEd Ex. 35.0, 12:258-66). In ComEd's opinion, ***231** there is no basis to conclude that the rates per unit of measure are unreasonable and have led to dramatic increases in costs as suggested by Mr. McGarry.

CCC's reliance on BSC bills is, according to ComEd, misplaced. ComEd states that these reports have nothing to do with determining the justness and reasonableness of the rates charged. Assessment of the reasonableness of the rates occurs before the services are provided and the bills are issued through the negotiation of Service Level Agreement ('SLAs'), which establish the scope and pricing of services to be provided by BSC to ComEd in the upcoming calendar year. ComEd contends that it is during this process that one can compare the rates for services to be received to the costs of those services in prior years to determine the reasonableness of the rates. (Houtsma Sur., ComEd Ex. 35.0, 13:279-88).

Staff

****71** Staff witness Ms. Hathhorn testified that an adjustment to reduce ComEd's affiliate charges from BSC by $10,117,000 was necessary to reflect a normal level of test year costs in Accounts 921, Office Supplies and Expenses and Account 923, Outside Services Employed, rather than using the historical 2004 amounts, since the 2001 through 2004 amounts vary greatly - from approximately $74 million in 2002 to a high of $119 million in the test year, 2004. (Staff Ex. 1.0, Schedule 1.8 and Staff Ex. 12.0, Schedule 12.8).

In her rebuttal testimony, Ms. Hathhorn modified her proposed adjustment to also account for EDSS costs in the calculation of the four year average balance. This changed the range of ComEd's costs from a low of $77 million in 2002 to a high of $143 million in 2004. (Staff Ex. 12.0, Schedule 12.8, Column (h)). Ms. Hathhorn's revised adjustment of $10.117 million results in a test year normalized balance of $117.8 million. FN11 However, Ms. Hathhorn testified that she could not accept ComEd's further refinement of the adjustment for centralization of BSC functions (ComEd Ex. 18.1, Schedule 1, line 14) because her modification to include the EDSS expenses in the four-year average accomplishes the same result. (Staff Ex. 12.0, Schedule 12.8, line 5). Further, she stated that she could not accept ComEd's centralization adjustment because there was no support for it, noting that ComEd's workpapers on the BSC portion provided only circular references - from one data request response to another-with no underlying account balance or source documentation provided. (Staff Ex.12.0, p. 14).

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CCC witness Mr. McGarry testified that ComEd's GSA expenses should be reduced to account for the costs associated with the divestiture of Exelon business entities that did not clearly benefit ratepayers. (CCC Ex. 5.0 at 38, L. 750-753). CCC maintained that the large increase in the level of corporate governance services charged to ComEd as a result of Exelon Corporation's sale of the Enterprise Businesses should be rejected by the Commission. CCC witness McGarry recommended that the Commission disallow $5.791 million in costs that did not benefit ratepayers. (CCC Ex. 2.02, Schedule MJM-14, (rev. Mar. 20, 2006)).

CCC witness Mr. McGarry testified that ComEd's GSA expenses should be reduced to account for the costs associated with the divestiture of Exelon business entities. Mr. McGarry states that this transaction did not clearly benefit ratepayers. CCC maintains that the large increase in the level of corporate governance services charged to ComEd as a result of Exelon Corporation's sale of the Enterprise Businesses should be rejected by the Commission. CCC witness McGarry recommends that the Commission disallow $5.791 million in costs that did not benefit ratepayers. Mr. McGarry also suggests that the Commission evaluate the charges and cost from this agreement between ComEd and Exelon BSC. According to Mr. McGarry this would be analogous to an audit, but he set no time frame for this request.

***232** *Commission Analysis and Conclusion*

****72** ComEd proposed a revised figure of $143,392,000 in rebuttal testimony for expenses allocated to ComEd (and recorded in A&G Accounts 920, 921 and 923) for the provision by BSC of centralized services in the test year. ComEd argues that there is no realistic expectation that Exelon BSC costs will revert back to the historical levels in place before 2004. According to the Company, it would be unrealistic to assume that a reorganization of this magnitude, with severance costs of $67 million, would be implemented for one year only, yet this is the result of Ms. Hathhorn's proposed adjustment. ComEd states that these facts establish both why there was a sharp increase in BSC costs in 2004 and why this higher level of BSC costs will continue in future years. Although overall ComEd costs were reduced as a result of the Exelon way, this centralization increased the portion of ComEd's costs that are attributed to Exelon BSC in the test year.

Staff in their response is proposing an adjustment to also account for EDSS costs in the calculation of the four year average balance. This changed the range of ComEd's costs from a low of $77 million in 2002 to a high of $143 million in 2004. Based on this four year average, Staff is proposing a revised adjustment of $10.117 million results in a test year normalized balance of $117.8 million. However, Staff 's witness Ms. Hathhorn testified that she could not accept ComEd's further refinement of the adjustment for centralization of BSC functions because her modification to include the EDSS expenses in the four-year average accomplishes the same result. Further, she stated that she could not accept ComEd's centralization adjustment because there was no support for it, noting that ComEd's work papers on the BSC portion provided only circular references- from one data request response to another - with no underlying account balance or source documentation provided.

ComEd responded that although Ms. Hathhorn's average includes EDSS, and the test year amount to which she compares the average also includes EDSS, because EDSS is higher in the 2004 test year than the prior years her averaging methodology has the effect of disallowing the increase in EDSS costs that resulted from centralization. Thus, the issue is whether on a going forward basis, the cost level for services provided by the EDSS department of BSC is more likely to be $9 million (the result of Ms. Hathhorn's four year 'normalization' through averaging) or approximately $24 million. The Company argues that nothing in the record apart from the mathematics of averaging, supports a conclusion that during the years the rates established in this case will be in effect, the level of BSC costs for centralized services, and particularly EDSS services, will be anywhere close to $9 million. ComEd claims it has provided unrebutted evidence as to why the BSC costs increased and why the level of costs resulting from the reorganization will continue in future years. ComEd point out that it has provided unrebutted evidence that BSC costs in 2005, were virtually the same as in 2004.

****73** Even CCC witness Mr. McGarry has acknowledged that the effects of centralization should be removed from Ms. Hathhorn's adjustment. ComEd witnesses testified that these costs will continue, and CCC witness McGarry has testified that these costs should be removed from Ms. Hathhorn's adjustment. ComEd claims it has provided a logical explanation of why a reorganization of the magnitude of Exelon Way would not be done for one year (the 2004 test year) only, and 2005 costs confirm that the test year costs are at a level likely to be incurred in future years. According to ComEd, Staff has supplied no affirmative evidence to the contrary.

ComEd asserts that the two arguments of CCC should be rejected. In regard to the increases in BSC costs allocated to ComEd as a result of the sale of Enterprises not being allowed, ComEd claims it has shown that such allocations can increase or decrease costs based on numerous factors. In regard to CCC's call for some form of evaluation or audit of BSC costs, ComEd argues that the record is devoid of any evidence that the BSC costs are unreasonable and thus there is no basis for an audit.

The Commission finds that there is no ***233** indication that the four year average as proposed by Staff will accurately reflect the costs allocated to Exelon BSC. As pointed out by ComEd, the costs for the 2005 year were almost the same as 2004. Further, ComEd has demonstrated that the increases in BSC costs attributable to centralization resulted in overall cost savings to ComEd. Therefore, the adjustments proposed by Staff and CCC are rejected and the proposal of ComEd is adopted. In addition, the Commission finds no basis on the record for CCC's suggestion that the Commission conduct an audit of the charges by Exelon BSC to ComEd under the GSA.

4. SALARY AND WAGE EXPENSE

ComEd

[37] According to ComEd, it recognized that salary and wage expense at the end of the 2004 test year reflected the impact of certain permanent staff reductions related to the Exelon Way program, and made a downward *pro forma* adjustment to the test year expense. Specifically, ComEd lowered that salary and wage expense by $5,084,000 to ‘normalize‘ that expense for periods beyond 2004. (Hill Dir., ComEd Ex. 5.0 Corr., 38:817-1820; ComEd Ex. 5.1, Sched. C-2.13).

ComEd, in its rebuttal testimony, agreed to Staff's adjustment to remove $1,174,000 of ComEd's *pro forma* salary and wage increases adjustment for 2005.

Regarding Mr. Effron's proposal to lower ComEd's salaries and wage expense further because he believes that ComEd is recovering expense for more employees than it actually pays, ComEd contends that its 2004 wage and salary expense number is based on actual costs paid in 2004, not the number of employees. (*E.g.*, Hill, Tr. at 932:8-933:5). ComEd states that because the salary and wages expense number reflected in ComEd's revenue requirement did not include any funds for temporarily vacant positions, it is improper to use vacancies as a basis for any further downward adjustment as Mr. Effron's proposal does.

****74** ComEd witness Mr. Hill described the ‘significant difference‘ between ComEd's *pro forma* adjustment made before the case was filed and Mr. Effron's additional adjustment. ComEd's reduction in expenses was to account for the reduction in employees due to the Exelon Way because ComEd considers and is committing that the Exelon Way reductions will be permanent vacancies. (Hill Reb., ComEd Ex. 19.0 Corr., 45:956-59). ComEd contrasted these reasons to Mr. Effron's adjustment, opining that he incorrectly assumes that the vacant positions will result in permanent reductions to ComEd labor costs. (Hill Reb., ComEd Ex. 19.0 Corr., 46:960-61). ComEd posits that it could have adjusted its payroll costs upward to recognize the temporary nature of the vacant positions, but did not do so. (Hill Reb., ComEd Ex. 19.0 Corr., 46:961-63).

ComEd also presented the testimony of John Costello, ComEd's Chief Operating Officer and the person charged with managing the ‘people who work to keep the lights on.‘ (Costello Reb., ComEd Ex. 13.0 Corr., 1:15- 16). Mr. Costello testified that the vacant positions relied upon by Mr. Effron were merely temporary vacancies. Mr. Costello also testified that ComEd's proposed operating expense level (which reflects only ComEd's adjustment) ‘appropriately includes the costs that ComEd will incur in the future to maintain‘ the ‘work force [that] provide[s] safe, efficient, and reliable electric supply. ‘ (Costello Reb., ComEd Ex. 13.0 Corr., 34:772-75). Mr. Costello further testified that ‘[e]mployee levels vary throughout the course of the year based on staffing changes‘ and that ‘[a] vacancy for a position may not be filled immediately‘ because

ComEd takes the time necessary to ensure it hires the right person for the job. (Costello Reb., ComEd Ex. 13.0 Corr., 34:778-35:782). Finally, Mr. Costello summed up the impact of Mr. Effron's proposal by explaining that it ‘would mean that ComEd would not be able to fill any of its current vacancies. It means that ComEd would not be able to hire the employees it wants to hire to keep the lights on.‘ (Costello Reb., ComEd Ex. 13.0 Corr., 35:790-92).

ComEd states that Mr. Effron arrived at his specific adjustment based on results-oriented ***234** mathematical manipulations which are patently unfair. ComEd asserts that while Mr. Effron had available 9 months of 2005 employee data, he instead chose to employee a ‘six month average‘ for his employee count and based that average upon ‘the six months ended September 2005.‘ (Effron Dir., AG Ex. 1.0, at 18:20). ComEd attests that the average employee count for the full nine months of 2005-5,503 - was higher than the average for the six month period Mr. Effron used - 5,482. Tr. at 1627:91628: 5. According to ComEd, the record further reflects that if one looked at employee data for all of 2005 (data then available), the number would be still different - somewhere in-between Mr. Effron's six months number and the nine-month number. (Tr. at 1634:14-19). ComEd argues that relying on short-term averages in this fashion fails reasonably to account for normal variances in employment. ComEd avers that in the past, when the Commission Staff has challenged employee counts as overstated using an average, they conducted an intensive study spanning 26 months to ensure that the figures accounted for the numerous variances that impact labor force during any given period. (*See,e.g.* , *Governor's Office of Consumer Services v. ICC*, 242 Ill. App. 3d 172, 189-90 (1st Dist. 1992)).

AG

****75** The AG asserts that ComEd is seeking to recover salary and wage expense for vacant labor positions that ComEd failed to prove will ever be filled. In its rate case filing, the Company made a *pro forma* reduction to wage and salary expense to account for the one-time affect of workforce reductions due to the Exelon Way program. (AG Ex. 1.0 at 16). However, the Company only adjusted wage and salary expense to account for reductions to slightly more than half of the total reduction of employees that occurred in the test year. The AG asserts that a larger *pro forma* reduction to wage and salary expense was necessary to properly reflect the appropriate level of employees necessary to provide delivery service to ratepayers.

According to the AG, ComEd witnesses asserted that the employees in Mr. Effron's adjustment were not related to the one-time Exelon Way reductions or otherwise to the Exelon merger, and were instead only ‘temporary vacancies‘. Yet, ComEd did not assert that the full-time equivalent employee level ever reached the level that ComEd assumes in its filing; and, ComEd has provided no evidence that these ‘temporary vacancies‘ have been filled, when they will be filled, or if ComEd's employment roles are ever truly full. Therefore, the AG argues that ComEd has not met its burden of proving that recovery of the cost of these vacant positions is just and reasonable.

Accordingly, the AG's witness Effron recommended an adjustment to the Company's *pro forma* reduction to wage and salary expense to reflect the effect on expenses of the decline in the number of full-time equivalent***235** employees taking place after the end of the test year into 2005 by taking the average of full-time equivalent employees for the 6 months ending September 2005. The net effect of this analysis is to reduce ComEd's proposed *pro forma* test year wage and salary expense by $5,488,000.

Commission Analysis and Conclusion

In its rebuttal testimony, ComEd accepted a proposal from Staff reflecting a downward adjustment of $1,174,000. This adjustment satisfied Staff's objection to this issue and was reflected in the Company's revised Schedules C-1, C-2 and C-2.1.

The AG's witness, Mr. Effron, recommends a further downward adjustment in wage and salary expense. He argues that the adjustment to date accounts for slightly more than half of the total reduction of employees that occurred in the test year, and that there is no evidence that positions that ComEd characterizes as temporary vacancies will be filled. The AG's further adjustment uses the average of full-time equivalent employees for the six months ending September 2005 to reduce the Company's *pro forma* wage and salary expense by $5,488,000. The AG asserts that this reflects the decline in the number of full-time equivalent employees taking place after the end of the test year into 2005.

ComEd contends that, in choosing his six-month sample, Mr. Effron failed to use available data and obtained a result that is extreme and unrepresentative. ComEd stresses that relying on short-term averages in this fashion fails reasonably to account for normal variances in employment. ComEd also avers that its reduction in expenses accounts for a permanent reduction in employees due to the Exelon Way program.

****76** The Commission finds that reliance upon a short-term average rather than the test year likely will fail to reasonably account for normal variances in employment and is subject to misleading manipulation. Mr. Effron's selection of a short time period and his failure to articulate reasons for excluding available data leads the Commission to reject the AG's proposed further adjustment and approve ComEd's proposed Salary and Wage Expense.

5. SEVERANCE EXPENSE

ComEd

[38-40] ComEd seeks recovery of two types of severance costs in this proceeding - those that occur in the normal course of business, and those that flow from a defined cost savings initiative, *i.e.*, the Exelon Way program. ComEd states that the first type is recoverable as an ordinary recurring business expense. Regarding the second type - savings related to the Exelon Way program - ComEd noted that it is recoverable as a ‘cost savings program that is anticipated to result in annual jurisdictional savings‘ of more than $1,000,000. (83 Ill. Admin. Code § 285.3215(a)). ComEd's proposed operating expenses include an appropriate level of severance expense, including an amortized level of the Exelon Way severance expenses. (*E.g.*, Hill Reb., ComEd Ex. 19.0 Corr., 46:972-49:1025).

In response to the AG's proposal to disallow ComEd's severance expense, ComEd contends that no one, including the AG's witness Mr. Effron, disputes that ComEd should recover severance costs incurred in the ordinary course of business. (Effron Reb., AG Ex. 3.0 Corr., 14:14-16). ComEd maintains, however, that Mr. Effron proposes reducing the requested amount by employing an average based on the years 2001 through 2005 (Effron Reb., AG Ex. 3.0 Corr., 14:17-18), even though severance cost data for the year 2000 is in the record and available. ComEd argues that by excluding the year 2000, Mr. Effron omits $5.8 million in severance costs, which reduces ComEd's annual recovery by more than $800,000. (Hill Sur., ComEd Ex. 36.0 Corr., 39:879-89).

Although Mr. Effron states that the years 2001-2005 constitute a more recent five year period than the years 2000-2004, ComEd Witness Mr. Hill testified ‘there is no reason to exclude the year 2000, because if an average is to be used, it should ‘include all data points that are of recent vintage and are in the record.‘ (Hill Sur., ComEd Ex. 36.0 Corr., 39:884-87). ComEd states that the AG has not objected to the use of year 2000 data to determine adjustments in other contexts. In addition, the AG has not taken exception to the use by other parties in this proceeding of historical averages that encompassed the 2000-2004 time period, such as Staff's proposed adjustment for uncollectibles expense. (Ebrey Dir., Staff Ex. 2.0, Sched. 2.5). According to ComEd, Mr. Effron objects to use of 2000 data here only because it suits his present purposes.

In addition, ComEd states that since the purpose of Mr. Effron's average is to determine a proper level of costs going forward, ‘[w]hether the amount may or may not have been included in determining a prior revenue requirement is irrelevant.‘ (Hill Sur., ComEd Ex. 36.0 Corr., 39:882-84).

****77** ComEd also posits that Mr. Effron claims that

ComEd 'does not anticipate that any severance costs will be incurred in 2006 and 2007.' (Effron Reb., AG Ex. 3.0 Corr., 15:8-9). However, in ComEd's opinion the record is clear that the portion of the exhibit to which Mr. Effron refers concerns the Exelon Way initiative, not the severance costs incurred in the ordinary course of business separate from Exelon Way. (Hill Reb., ComEd Ex. 19.0 Corr., ***236** Sched. 16, p. 2). Further, there is no reference to 2006 or 2007 on the document referenced by Mr. Effron. (Hill, Tr. at 874:14-875:5, 930:3-9).

In regard to the severance costs related to the Exelon Way Program, ComEd states that the Exelon Way initiative began in mid-2003 as a means to reduce costs through 'integration and centralization of support functions, consolidation and alignment of business units and standardization and simplification of operating processes.' (Hill Reb., ComEd Ex. 19, Sched. 16, p.2). ComEd states that it incurred approximately $158 million in severance costs in 2003 and 2004. (Hill Reb., ComEd Ex. 19.0 Corr., 46:1008-10). ComEd avers that test year expenses in this proceeding include $21 million of the total severance costs related to the Exelon Way savings program, and that inclusion of this amount results in an implied amortization period of over seven years ($158 million divided by $21 million equal 7.5 years). (Hill Reb., ComEd Ex. 19.0 Corr., 46:1008-17).

ComEd refers to Section 285.3215 of the Commission's Rules, added in 2003, which confirms that it is reasonable for utilities to recover costs related to a 'cost savings program that is anticipated to result in annual jurisdictional savings in excess of …$1,000,000' and the 'initial costs of which are sought to be recovered in the test year.' 83 Ill. Adm. Code § 285.3215. ComEd contends that the costs to achieve the Exelon Way program savings fall squarely within the scope of Section 285.3215, and therefore recovery should be allowed. The severance costs related to the Exelon Way constitute 'initial costs' of the program that are sought to be recovered in the test year, 2004. (Hill Sur., ComEd Ex. 36.0 Corr., 40:894-99). ComEd attests that the Exelon Way initiative produced cost savings well in excess of the $1 million threshold, that those savings are already embedded in the 2004 test year costs (Houtsma Reb., ComEd Ex. 18.0 Corr., 3:46-50), and that that initiative will continue to produce significant cost savings going forward - $70 million in 2005, $73 million in 2006 and $75 million in 2007 (Hill Reb., Ex. 19.0 Corr., Sched. 16 p.2) - as well as expected savings past 2007. (Hill, Tr. at 871:1-6).

Mr. Effron first argues these costs should be disallowed because ComEd 'does not incur these expenses on a normal, ongoing basis, and it is unlikely that such costs will be incurred prospectively unless there is another major severance program.' (Effron Reb., AG Ex. 3.0 Corr., 15:20-16:1). According to ComEd, it is reasonable, and it is the point of Section 285.3215, to allow recovery of the 'initial costs' of 'cost savings initiatives' that will produce significant savings, without regard to whether those costs recur. ComEd states Mr. Effron does not even reference Section 285.3215 in his direct or rebuttal testimony, suggesting that he prepared such testimony without regard to the terms of that section. On cross examination, however, he acknowledged that Section 285.3215 concerned cost savings programs and did not (and could not) contend that it does not bear on this issue. (Effron, Tr. at 1618:9-1619:8). Furthermore, ComEd opines, if the severance costs were recurring, they would properly be recovered regardless of Section 285.3215, and there would have been no need for that section. As Mr. Hill testified: 'Of course, these costs do not occur every year. That is precisely why the Commission provided for utilities to propose recovery of [their] initial costs for costs savings programs.' (Hill Sur., ComEd Ex. 36.0 Corr., 40:907-09). According to ComEd, the fact that the Exelon Way severance costs do not recur is irrelevant to whether they can be recovered.

****78** Regarding the AG's position that shareholders will reap the benefits of such a program because future savings will not be reflected in rates and will more than pay for the program, ComEd states as an initial matter that the fact that the savings from an initiative will cover its costs cannot possibly be a basis to deny recovery of the costs, because no rational company would undertake such a program unless it expected net savings to occur.

ComEd contends that the AG's position fails to consider that shareholders are absorbing cost increases above the level of costs in the test year in this proceeding in other areas of ComEd's total costs to provide delivery services between now and the time rates from this proceeding go into effect - ***237** such as increased depreciation expense, 2006 employee salary increases, and increased health care costs to name a few. (Hill Sur., ComEd Ex. 36.0 Corr., 41:917-21).

ComEd further maintains that as a result of Exelon Way, the costs incurred directly within ComEd were reduced, and the overall effect was to reduce 2004 O&M costs by $66 million. (Houtsma Reb., ComEd Ex. 18.0 Corr., at 3:46-50). Thus, ratepayers are benefiting in rates from the program. In addition, ComEd states that Mr. Effron does not dispute that, as a result of Exelon Way: ‘ComEd expects to have sustainable savings for the three years past the test year of $70 million in 2005, $73 million in 2006 and $75 million in 2007;‘ the ‘Exelon W[ay] cost savings initiative has produced costs savings that are already embedded in test year costs;‘ and ‘that there will be expected savings from the Exelon W[ay] program past 2007.‘ (Effron, Tr. at 1621:20-1622:20).

AG

The AG addressed two different kinds of severance costs that ComEd seeks to recover in its proposed rates, event related costs and recurring costs. The AG's witness Mr. Effron proposes adjustments regarding both kinds of severance costs.

Event-Related Severance Costs ComEd proposed to include $21 million in the Exelon Way program, increasing operation and maintenance expense by $10 million associated with salary continuance severance costs, $8 million of special health and welfare benefits and $3 million of curtailments costs associated with pension and postretirement benefits plans. The AG asserts that these severance costs are not normal ongoing costs that the company incurs to provide electric service, noting severance cost amounts for earlier years of $652,000 in 2001 and $593,000 in 2002. The AG also asserts that severance expenses in 2005 through September were a negative $8.3 million to adjust for severance costs previously accrued in relation to the Exelon Way program.

The AG asserts that these costs are not normal severance expenses that ComEd will incur on a regular basis and ComEd has already recovered these costs by means of savings related to the Exelon Way program. By the end of 2006, the Exelon Way savings will be greater than the severance costs. ComEd has offered no evidence of plans for a program similar to the Exelon Way in the future. The AG asserts that ComEd has not shown how such costs will be incurred going forward. Accordingly, the AG asserts that severance costs related to Exelon way should not be recovered in ComEd's rates, which will not be effective until January 1, 2007.

****79** The AG's witness Mr. Effron eliminated the $10 million associated with salary continuance severance costs, $8 million of special health and welfare benefits and $3 million of curtailments costs associated with pension and postretirement benefits plans. The elimination of these three Exelon Way severance costs accrued in 2004 reduces test year operation and maintenance expense by $21,000,000.

Recurring Severance Costs

The AG does not oppose recovery of its recurring severance costs in rates, but disputes the amount proposed by ComEd. ComEd employs a five year average of recurring severance costs, using costs for the years 2000-2004. According to the AG, its witness Mr. Effron's adjustment employing a 2001-2005 five year average is more appropriate both because it is a more recent average and because the Commission already allowed for recovery of the $5.8 million of severance costs incurred in 2000 in ComEd's previous Delivery Service Case (ICC Docket No. 01-0423). Mr. Effron's adjustment to the Company's severance expense, based upon the Company's five-year average of normal severance expense for the true-up credit booked in the 2004 test year, increases operation and maintenance expense by $647,000.

The net effect of Effron's two adjustments to severance expense is to reduce *pro forma* test year operation and expense by $20,353,000. On a jurisdictional basis, this adjustment reduces *pro forma* test year operation and expense by $18,155,000.

****238** Commission Analysis and Conclusion*

Two types of severance costs are at issue in this proceeding. The first concerns costs that occur in the normal course of business. No party, including the AG, disputes that ComEd should recover severance costs incurred in the ordinary course of business. However, AG's witness, Mr. Effron, proposes reducing the requested amount by employing an average based on the years 2001 through 2005. (Effron Reb., AG Ex. 3.0 Corr., 14:17-18) ComEd argues that the severance cost data for the year 2000 is in the record and available. Mr. Effron offers three reasons in support of his exclusion of the year 2000 data. First, Mr. Effron argues that the recurring severance expense booked by the Company in 2000 was abnormally high in that year, and is not representative of expense incurred in the years since. Second, ComEd has not demonstrated that the substantially higher expense incurred in 2000 is representative of the expense the Company can expect to incur in the future. Third, while not challenging ComEd's use of a five-year average to estimate the normal recurring severance expense, the AG contends that the period 2001-2005 reflects the most recent data available. The Commission agrees with the AG, and adopts the recurring severance costs proposed by the AG using the five year average of 2001-2005.

The second type of severance costs at issue concerns those that flow from a defined cost savings initiative, *i.e.*, the Exelon Way program. The AG also recommended disallowing the severance costs from the Exelon Way initiative entirely because they are not recurring costs and the savings allegedly will not be reflected in rates. However, these arguments are without merit. The record is clear that there are already savings from the Exelon Way program that will be reflected in the rates in this proceeding. In addition, no party has disputed that, as a result of Exelon Way, at least 70 million dollars a year in savings are expected. These facts establish a clear basis for recovery consistent with Section 285.3215. Accordingly, the record establishes that ComEd properly seeks recovery of its initial severance costs for a program expected to produce hundreds of millions of dollars in savings over the life of these rates. Mr. Effron's proposed adjustment would deny ComEd any recovery of that cost, which removes the incentive created by Section 285.2315 to initiate such programs. ComEd's proposed severance expenses related to the Exelon Way program are just and reasonable and therefore are approved.

6. INCENTIVE COMPENSATION ComEd

****80 [41, 42]** ComEd states that, like nearly every major U.S. company, it includes incentive compensation as part of its overall employee compensation package. ComEd presents testimony from a compensation expert, Mr. Meischeid, that incentive compensation is a ubiquitous and necessary tool to recruit, to compensate, and to motivate employees. Mr. Meischeid testified that, given its wide use, ‘incentive compensation is not 'additional’ or 'optional' compensation that ComEd provides to employees, but a required element in the compensation program and a necessary cost of doing business.‘ Meischeid Dir., ComEd Ex. 12.0., 6:114-16. In addition, ComEd presented testimony from Mr. John Costello, ComEd's Chief of Operations, that ComEd must offer incentive compensation in order to provide the competitive compensation package necessary to attract and to retain high-quality employees. Meischeid Dir., ComEd Ex. 12.0, 5:107-6:112; Costello Reb., ComEd Ex. 13.0 Corr., 23:516-19. Mr. Meischeid explained that companies use incentive compensation ‘to focus employees on key goals in order to improve performance‘ because they ‘have found that providing monetary incentives to employees is more effective than providing salary and benefits only.‘ Meischeid Dir., ComEd Ex. 12.0, 5:103-06.

As an integral part of total compensation, ComEd maintains that incentive compensation should not be analyzed separately from base salary when determining whether recovery of employee compensation expense through rates is proper. ComEd frames the question as ***239** whether the total levels of cash compensation - base salary plus incentive compensation - are reasonable. Mr. Meischeid compared the levels of total cash compensation that ComEd pays employees in various positions to the levels of total cash compensation that ComEd's utility peers pay to their employees in comparable positions. Meischeid Dir., ComEd Ex. 12.0, 7:147-8:158; 9:179-87. Based on that comparison, Mr. Meischeid testified that ComEd's pay levels fall 'within the competitive range versus market.' *Id.*, at 11:220-26.No party has challenged ComEd's total cash compensation, or incentive compensation, as unreasonable or excessive.

ComEd's incentive compensation plan, sometimes referred to as the Annual Incentive Plan or 'AIP,' extends to nearly all ComEd employees, and 'provides employees with the opportunity to earn cash awards based on the achievement of operational, individual and financial goals.' Meischeid Dir., ComEd Ex. 12.0, 6:119-23. Incentive compensation payments are based upon ComEd's performance with respect to certain goals, or performance measures. The plan contains two types of performance measures: funding and allocation. As their names suggest, performance on a funding measure determines whether the plan will receive funding, and performance on an allocation measure determines how payments for incentive compensation, once funded, are divvied up among employees.*Id.*, at 11:227-12:256.

ComEd's plan employs four funding measures: '1) SAIFI - System Average Interruption Frequency Index, 2) CAIDI - Customer Average Interruption Duration Index, 3) O&M and Capital Expense, and 4) EPS [earnings per share]. ' Meischeid Dir., ComEd Ex. 12.0, 12:260-63. Fifty percent of plan funding is based on the SAIFI, CAIDI and O&M measures together, and the other fifty percent is based on EPS.*Id.*, at 13:284-87.

****81** ComEd states that, for its incentive compensation plan, the amount of funding for each measure corresponds to the performance thereunder. Three performance levels are set: threshold, target and distinguished. No funding occurs unless performance reaches the threshold level. Funding increases as performance moves to target level, and finally is capped at the distinguished level; however, payouts are assured once the threshold level is reached. Payments for incentive compensation track the measures for funding. ComEd has requested recovery of incentive compensation expense at the target level for the 2005 plan year. Meischeid Dir., ComEd Ex. 12.0, 14:292-94.

ComEd also notes that overall incentive compensation awards from all measures - SAIFI, CAIDI, O&M costs and EPS - may be increased or decreased based on ComEd's performance on 'customer satisfaction,' as measured by the American Customer Satisfaction Index Proxy (ACSI Proxy). Meischeid Dir., ComEd Ex. 12.0, 13:272-74.

ComEd states that its total cash compensation levels are reasonable in amount and that, because it improves employee performance, incentive compensation is prudent. Thus, ComEd posits that its total cash compensation expense - base salary plus incentive compensation - merits full recovery through rates.

ComEd notes that both Staff and the AG propose to deny ComEd recovery of the incentive compensation portion of its total cash compensation expense but allegedly without disputing that ComEd's total cash compensation expense (including incentive compensation) is reasonable and prudent. ComEd maintains that the proposed disallowance contravenes the well-established principle that rates 'must allow the utility to recover costs prudently and reasonably incurred.' *Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111, 121 (1995) ('*Citizens 1995*'). Regarding Staff and the AG's argument that ComEd has not satisfied the Commission's test for recovery of incentive compensation expense, ComEd states that the correct standard for recovery of employee compensation expense - base salary plus incentive compensation - is as stated in *Citizens 1995*; namely, whether that expense is reasonable and prudent.

In the past, the Commission has imposed two fundamental requirements for recovery of incentive compensation expense: (1) an 'historical pattern of paying incentive compensation' ***240** to serve as a basis to determine whether, and how much, incentive compensation expenses will be incurred going forward; and (2) evidence that ‘the incentive compensation payments provided benefits to ratepayers.‘ *Central Illinois Pub. Serv. Co. and Union Elec. Co.* , ICC Docket 00-0802 (Order Dec. 11, 2001) at 19; *Consumers Illinois Water Co.*, ICC Docket No. 97-0351, 1998 WL 34302196, at *17 (Order June 17, 1998) (same).

ComEd believes that its incentive compensation programs and the expenses of those programs included in the revenue requirement amply meet each of those criteria. ComEd maintains that it has demonstrated a commitment to incentive compensation which ensures ComEd will continue its incentive compensation program going forward. Mr. Costello, who is charged with ensuring that ComEd has the personnel necessary to provide proper service, described incentive compensation as ‘an actual and longstanding cost.‘ Costello Reb., ComEd Ex. 13.0 Corr., 23:520-21.

****82** Regarding, Ms. Ebrey's worry that the goals in the plan may not be met, ComEd notes that ‘for each of the past four years, ComEd has paid total incentive compensation at levels *above* target.‘ Hill Reb., ComEd Ex. 19.0 Corr., 51:1116-17 (emphasis original). ComEd states that it consistently incurs incentive compensation expense, and does so at levels above the target level at which it requests recovery. Regarding Staff's contention that ComEd executives have the option to cancel the AIP, Mr. Costello stated that ‘ComEd does not intend to eliminate its compensation program.‘ Costello Reb., ComEd Ex. 13.0 Corr., 22:514. ComEd notes that, despite Staff's contention to the contrary, because prior versions of ComEd's plans embraced the same fundamental goals as the current plan, ComEd's payment record serves as a reliable guide to ComEd's likely payouts going forward. ComEd states, in response to Ms. Ebrey's claim that there is no sufficient explanation of why the targets have varied significantly from year to year, that it has reduced the target level of incentive compensation at the individual employee level. ComEd notes that the variance in the aggregate target levels exhibits a decrease consistent with the reduction in employees over the past several years.

ComEd's compensation expert Mr. Meischeid has testified that companies employ incentive compensation to focus employees ‘on key goals in order to improve performance,‘ and because they ‘have found that providing monetary incentives to employees is more effective than providing salary and benefits only. ‘ Meischeid Dir., ComEd Ex. 12.0, 5:103-04. ComEd argues that, without incentive compensation, ComEd could not ‘continue to attract the talent necessary to provide safe, efficient and reliable service to customers. ‘ Costello Reb., ComEd Ex. 13.0 Corr., 16:381-85. Mr. Meischeid testified that, absent incentive compensation, ComEd cannot offer a competitive compensation package. Meischeid Dir., ComEd Ex. 12.0, 5:107-6:112.

ComEd also notes that its incentive compensation program has led to tangible customer benefits that correspond to plan goals. These include measurable improvement in the CAIDI and SAIFI service reliability measures, improved customer satisfaction ratings, and lower Distribution O&M expenses in the 2004 test year due to improved efficiency and productivity. Costello Reb., ComEd Ex. 13.0 Corr., 21:469-71; Costello Sur., ComEd Ex. 30.0, 9:197-201; DeCampli Reb., ComEd Ex. 14.0 Corr., 13:249-64; Houtsma Reb., ComEd Ex. 18.0 Corr., 7:141.

ComEd states that financial goals are those based on net income, EPS or other earnings-based measures, whereas operational goals are those based upon business functions such as O&M costs, reliability, safety and customer service. Meischeid Dir., ComEd Ex. 12.0, 16:331-44. ComEd highlights its most recent delivery services rate case, in which the Commission found recovery proper because the plan ‘reduced *operating expenses* and *created greater efficiencies.*‘ Commonwealth Edison Co., ICC Docket 01-0423 (Order, March 28, 2002), at 121 (emphasis added). ComEd also notes that its incentive compensation program has in fact led to tangible customer benefits that correspond to plan goals. These customer benefits include measurable improvement in the CAIDI ***241** and SAIFI service reliability measures, improved customer satisfaction ratings, and lower Distribution O&M expenses in the 2004 test year due to improved efficiency and productivity. Costello

Reb., ComEd Ex. 13.0 Corr., 21:469-71; Costello Sur., ComEd Ex. 30.0, 9:197-201; DeCampli Reb., ComEd Ex. 14.0 Corr., 13:249-64; Houtsma Reb., ComEd Ex. 18.0 Corr., 7:141. Furthermore, ComEd states that although a reduction in O&M costs could correspond with increased earnings, ‘financial‘ goals trigger incentive compensation payments only when earnings targets are hit. ComEd highlights that the Commission has regularly recognized that incentive compensation programs that reward employees for lowering operating costs benefit customers.*See Commonwealth Edison Co.*, ICC Docket 01-0423 (Order, March 28, 2002); *Consumers Illinois Water Co.*, ICC Docket 03-0403 (Order, April 13, 2004), at 14-15; *Northern Illinois Gas Co.*, ICC Docket 95-0219 (Order, April 3, 1996), at 27.

****83** Finally, ComEd stresses that the entire incentive compensation plan - both the operational and the financial aspects - has a customer satisfaction overlay that brings the entire focus of the plan to that most basic customer benefit. ComEd states that contrary to Ms. Ebrey's assertion that the ‘shareholder protection feature‘ (which applies only to above-target payouts for which ComEd does not seek recovery) focuses ComEd's plan on shareholder benefit, the customer satisfaction overlay, which does apply to the entire plan and can increase or decrease the entire award, strongly focuses ComEd's incentive compensation plan on customer benefit.

In addition to the evidence regarding the Commission test set forth above, ComEd states that in place of that test, the appropriate standard should be under the ‘reasonable and prudent‘ test used for expenses generally. ComEd explains that before incentive compensation fully emerged as a ubiquitous method of compensating employees, it made sense to ensure that a utility seeking recovery for incentive compensation was not merely experimenting with the latest trend, but actually was committed to the program. ComEd shows that nearly every utility now uses incentive compensation as part of its total compensation package because of the positive impacts on employee performance and recruitment. ComEd states that that there is now no reason to suspect that ComEd's use of incentive compensation is any more novel or temporary than its payment of base salary or health benefits.

Staff

Staff witness Ebrey proposed an adjustment to disallow costs of the Company's Annual Incentive Plan (‘AIP‘) and Long Term Incentive Plan (‘LTIP‘) for five reasons. First, Ms. Ebrey stated that ComEd's incentive compensation plans are dependent upon financial goals of the Company which benefit shareholders and not ratepayers. (ICC Staff Exhibit 2.0, pp. 15-18) As a result, Ms. Ebrey concluded that these types of goals are based on circular reasoning; that is, the larger the rate increase granted, the more success ComEd will have in achieving its earnings goals. (ICC Staff Exhibit 2.0, p. 17) Further, she noted that since these goals primarily benefit shareholders, shareholders should bear the cost. (*Id.*) Second, Ms. Ebrey testified that the goals in the plans may not be met and, in that event, no cost would be incurred by ComEd yet ratepayers would have provided funding. (*Id.*, pp. 18-21) She was concerned that there was no mechanism to protect ratepayers should ComEd not achieve its 2005 level in the future. (*Id.*, p. 18) Third, Ms. Ebrey testified that ComEd's incentive compensation plans are discretionary and may be discontinued at any time. (*Id.*, pp. 21-22) Fourth, Ms. Ebrey stated there is not sufficient comparable historical data on which to determine if the test year level is reflective of a ‘normal‘ level. (*Id.*, p. 22) She testified that her concern results from a review of plan descriptions that indicates the plan has gone from a very basic plan with limited goals in 2002, to a much more complex plan in 2003-2004 and back to a simpler plan in 2005. (*Id.*) Finally, Ms. Ebrey testified that the disallowance of the costs of incentive compensation programs under the instant facts is consistent***242** with prior Commission Orders. (*Id.*, pp. 23-24)

****84** In rebuttal testimony, Ms. Ebrey clarified that the costs from both incentive compensation plans should be disallowed. (ICC Staff Exhibit 13.0, pp. 12-14) Further, Ms. Ebrey disagreed with assertions in ComEd's rebuttal testimony that it has satisfied the Commission's test for recovery of incentive compensation costs. Ms.

Ebrey noted that the Commission has spoken for itself regarding the kind of evidence it needs to see when deciding what portion, if any, of incentive compensation costs should be recovered. (*Id.*, pp. 16-17) Ms. Ebrey testified and Staff argues in its Initial Brief that ComEd has not satisfied the Commission's test for recovery of incentive compensation costs. (ICC Staff Exhibit 13.0, p. 17; Staff Init. Br., p. 54)

Staff further asserts that ComEd was unable to quantify any reductions to the requested rate increase associated with its incentive compensation plans. In response to ComEd's argument that reductions to incentive compensation would result in increases to other components of compensation, Staff pointed out that ComEd could not identify any increases to its total compensation package as a direct result of the Commission's disallowing $24 million of incentive compensation expense in ICC Docket 01-0423. (Staff Init. Br., p. 55) Additionally, Staff noted that the Company could not cite any instance where it has filed for a rate decrease as a result of these alleged lower costs. (*Id.*)

AG

The AG asserts that ComEd has failed to meet its burden of proving that recovering its incentive compensation program costs is just and reasonable. Citing the recent holding in the most recent Nicor Gas rate case, the AG noted that it is Commission practice to disallow incentive compensation programs where the utility cannot demonstrate any benefit to ratepayers. ICC Docket No. 04-0779, *Northern Illinois Gas Company Proposed general increase in natural gas rates ('Nicor Order')*, Order, September 20, 2005 at 44 ('Costs related to incentive compensation are recoverable in rates only if the utility demonstrates tangible benefits to ratepayers.'); *citing* ICC Docket No. 03-0403, *Consumers Illinois Water Company Tariff seeking general increase in water rates for the Kankakee Water Division*, Order, April 13, 2004 at 15 ('[T]o recover incentive compensation, the plan must confer upon ratepayers specific dollar savings or other tangible benefits.'); ICC Docket No. 01-0696, *Mid-American Energy Company Proposed general increase in gas rates* , Order, September 11, 2002 at 10 (requiring evidence of 'specific dollar savings or any other tangible benefit for the ratepayers'); ICC Docket No. 01-0432, *Illinois Power Company Proposed Revisions to Delivery Tariff Sheets*, Order, March 28, 2002 at 42-43 ('the Commission has generally disallowed such expenses except where the utility has demonstrated that its incentive compensation plan has reduced expenses and created greater efficiencies in operations.').

The AG states that ComEd has not provided any evidence that its incentive compensation program confers upon ratepayers specific dollar savings or other tangible benefits. Instead, ComEd has argued that this incentive compensation is part of the median wage necessary to attract skilled employees, and should be recoverable on those grounds alone. ComEd Ex.13.0 at 16. However, the AG noted that Nicor Gas attempted the very same argument in front of the Commission for its most recent rate case without success.*Nicor Order* at 45. Therefore, the AG asserts that ComEd has not made the necessary showing to justify inclusion of its incentive compensation program in rates, as it is ComEd's burden to do, and that the Commission should once again reject such a proposal. In accordance with this position, the AG's witness Effron eliminated incentive compensation and reduced *pro forma* test year expenses by $16,531,000.

Commission Analysis and Conclusion

****85** All parties appear to agree on the standards the Commission should employ when deciding whether to allow a company to recover the cost of its incentive compensation program. In ***243** ComEd's previous rate case, Docket 01-0423, we stated that such expenses should be recovered if the incentive compensation plan has 'reduced expenses and created greater efficiencies in operations' and thus, it 'can reasonably be expected to provide net benefits to ratepayers.' Neither ComEd nor Staff nor the AG challenge the Commission's earlier pronouncements that 'the plan must confer upon ratepayers specific dollar savings or other tangible benefits.' (04-0779 at 44; 03-0403 at 15; 01-0696 at 10.) Where the parties disagree is the extent to which ComEd's incentive compensation plan is shown to provide benefits to ratepayers. While ComEd makes the case that all parts of its incentive compensation plan meet the Commission's standards, Staff and the AG assert that no amount of the proposed $28,787,000 meets such standards.

Turning our attention to the individual parts of the incentive compensation structure, we agree with Staff and the AG that the earnings per share ('EPS ') funding measure, which constitutes fifty percent of overall plan funding, should not be allowed to be recovered through rates. As the name of the funding measure suggests, the primary beneficiaries of increased earnings per share are shareholders, not ratepayers. While it is true that the entire plan funding is dependent on 'customer satisfaction', as measured by some customer survey benchmark, we are not convinced that the link between responses to such a generic and broad customer survey and individual employee performance is strong enough to warrant recovery of incentive payments for meeting financial goals. Additionally, we believe customer satisfaction is more accurately measured by ComEd's own performance indices, such as the System Average Interruption Index Frequency Index ('SAIFI') and the Customer Average Interruption Duration Index ('CAIDI'), even though we applaud ComEd for using the customer survey proxy as the trigger for overall incentive plan funding.

When it comes to the other three components of the incentive plan, which constitute the other fifty percent of the plan's total funding, we believe it is hard to ignore the tangible benefits to ratepayers that result from meeting those operational goals. The SAIFI and CAIDI are obviously linked directly to ComEd's actual operational performance and thus it is hard to argue that an improvement in said measures does not benefit ratepayers; in this case through increased reliability. Not only can such an incentive structure 'reasonably be expected to provide net benefits to ratepayers', the record shows that these reliability performance measures have indeed been shown to improve since the inception of the incentive plan. Staff acknowledged that the portion of total incentive compensation costs that is based on operational key performance indicators can be recovered through rates and we find that there is a direct benefit to ratepayers though increased reliability as measured by SAIFI and CAIDI.

****86** Focusing on the funding measure that rewards employees for reducing O&M and capital expenses, the Commission finds that such funding measure meets the Commission's standard of reducing expenses and creating greater efficiencies in operations. Lowering O&M expenses, all else being equal, has the obvious effect of reducing the expenses to be recovered in future rate cases. While Staff argues that shareholders could also benefit from reduced O&M expenses through a potential concurrent increase in earnings, we note that the incentive compensation payments are linked directly to reduced O&M costs and thus an increase in earnings will not trigger any incentive compensation payments. In other words, increased earnings is a potential result, but not a necessary result of reduced O&M expenses. In addition, when we compare the incentive compensation costs allowed to be recovered in the company's previous rate case to the costs we allow here, we note that there was an additional financial trigger for the operational goals in the former. We do not have such a financial trigger here and thus there exists an even stronger link between incentive payments and the meeting of operational targets than in the previous rate case.

In accordance with our findings above, namely allowing recovery of the three funding measures associated with operational goals and ***244** disallowing recovery of the EPS funding measure, we reduce the Company's operating expenses by $8,418,500 and reduce the Company's rate base by $5,975,000.

7. UNCOLLECTIBLES EXPENSES

ComEd

[43] ComEd includes $15,803,000 of uncollectibles expenses in its operating expenses in its final revised proposed revenue requirement. ComEd's actual 2004 uncollectibles expenses were $37,054,000, of which ComEd determined that $13,129,000 was related to Illinois-jurisdictional delivery services (not including transmission) revenue at present rates.*E.g.*, Hill Dir., ComEd Ex.

5.0 Corr., 25:536-45; ComEd Ex. 5.1; Hill Reb., ComEd Ex. 19.0 Corr., 53:1170-54:1188; Hill Sur., ComEd Ex. 36.0 Corr., 42:950-43:969 and Sched. 10. ComEd also determines that the incremental increase in uncollectibles expenses that it would experience, based on its final revised proposed revenue requirement and its uncollectibles rate of 0.85%, is $2,674,000.*E.g.*, Hill Reb., ComEd Ex. 19.0 Corr., 52:1146-53:1169; Hill Sur., ComEd Ex. 36.0 Corr., 42:950-45:1019 and Sched. 1 Rev., pp. 1, 6. The figure of $15,803,000 of uncollectibles expenses in the revenue requirement is the sum of the foregoing $13,129,000 and $2,674,000 figures. That $15,803,000 is part of the final revised total of $146,979,000 of Customer Accounts Expenses (under the USoA, uncollectibles expenses are recorded in Customer Accounts Expenses, Account 904) included in the revenue requirement.*E.g.*, Hill Dir., ComEd Ex. 5.0 Corr., 24:517-19; Hill Sur., ComEd Ex. 36.0 Corr., Sched. 1 Rev.) [FN12]

ComEd states that it employs prudent and reasonable practices in managing its uncollectibles expenses.*E.g.*, Costello Dir., ComEd Ex. 3.0 Corr, at 29:619-32. ComEd stated that no party has submitted any claim or evidence to the contrary.

****87** ComEd characterizes Staff's proposal to disallow $1,988,000 of ComEd's 2004 test year uncollectibles expenses in the revenue requirement, and to reduce its incremental uncollectibles expenses, as arbitrary and incorrect. ComEd indicates that the use of the 2004 uncollectibles expenses amount to determine the uncollectibles expenses to be included in the revenue requirement rather than a five-year average is more appropriate and accurate than Staff's proposal, because the test year amount reflects ComEd's improved policies and practices for managing uncollectibles expenses, including stricter credit policies, implemented internal risk scoring systems, and other system changes, as illustrated by the fact that the total actual 2004 uncollectibles expenses are lower than the total actual uncollectibles expenses in 2003, 2002, and 2001. ComEd Ex. 5.1, Sched. C-16; Hill Reb., ComEd Ex. 19.0 Corr., 52:1146-58. In addition, ComEd notes that its uncollectibles rate of 0.85% is more appropriate and accurate than Staff's figure. As noted above, the jurisdictional test year uncollectibles expenses and uncollectibles rate of 0.85% are based on a detailed analysis of 2004 uncollectibles expenses and jurisdictional delivery services revenues by customer class, which, according to ComEd, is more appropriate and accurate than Staff's five-year average. ComEd argues that a methodology based on total expenses and revenues is consistent with ComEd's determination of all other components of its jurisdictional cost of service.*E.g.*, Hill Reb., ComEd Ex. 19.0 Corr., 52:1146-53:1169; Hill Sur., ComEd Ex. 36.0 Corr., 42:950- 44:1019. Staff's proposal is without merit.

ComEd describes CCC's proposal to disallow $3,748,636 of ComEd's 2004 uncollectibles expenses, and $18,021 of its jurisdictional 2004 outside collection agency expenses, as arbitrary and incorrect. ComEd submitted detailed evidence showing that to be the case. ComEd avers that CCC provides no valid basis for rejecting ComEd's careful direct assignment of its actual 2004 uncollectibles expenses, that CCC's general allocator is inappropriate and less accurate, and that its hypothesis regarding future decreases in uncollectibles expenses is pure speculation and is not a valid basis for an adjustment. Hill Reb., ComEd Ex. 19.0 Corr., 53:1170-55:1210; Hill Sur., ComEd Ex. 36.0 ***245** Corr., 45:1020-46:1033.

Finally, ComEd criticizes the AG's calculations because they assumed an uncollectibles expense rate of 0.64% (Effron Dir., AG Ex. 1.0, 4:2-5 and Sched. A), but the AG's assumption relies entirely on the ratio between ComEd's total actual 2004 uncollectibles expenses, before functionalization, and ComEd's total actual 2004 revenues, before functionalization. ComEd indicates that the AG offered no other basis for its assumption, and no supporting evidence. ComEd describes the AG's methodology as results-driven with the objective to find the lowest figure possible regardless of how weak or inconsistent the methodology material and support for the AG's proposal.

Staff

****88** Staff witness Ebrey proposed an adjustment to decrease the Company's test year uncollectibles expense, based upon a five-year average that produces an uncollectibles rate of 0.72%. Ms. Ebrey testified that the 0.85% uncollectibles rate proposed by the Company is higher than the overall uncollectibles rate in every one of the last five years and shows a 33% increase from the overall 2004 uncollectibles rate (.64%). (ICC Staff Exhibit 2.0, p. 26) She further noted that while Staff's proposed rate is also an increase (13%), Staff's rate is more representative on a going-forward basis because it reflects the Company's historic uncollectibles rates while allowing for an increase due to increased base rates. (*Id.*, pp. 26-27)

In rebuttal testimony, Staff witness Ebrey noted that the Company's proposed 0.85% uncollectibles rate, based upon its customer class analysis, is higher than the actual overall uncollectibles rate for 2004, which was only 0.64%. (ICC Staff Exhibit 13.0, pp. 23-25) Further, she stated that since the 0.72% uncollectibles rate proposed by Staff is less than the 0.85% uncollectibles rate proposed by ComEd, it would appear that Staff's proposal would be likely to more fully capture the effect of ComEd's more stringent credit and collection policies than would its own proposal. (*Id.*) Furthermore, Ms. Ebrey noted that ComEd's proposed overall uncollectibles as a percentage of base rate revenue for the test year is 0.72%, the same overall level that Staff is proposing. (*Id.*)

CUB-CCSAO-City

Mr. McGarry testified that the Company's requested uncollectible expense should be reduced to account for annual variability with a downward trend. CCC Ex 2.0 at 24, L. 519-528. Because ComEd's uncollectible expenses fluctuated from 2000 through 2004, (ComEd's uncollectible expenses ranged from a low of $37 million in 2004 to a high of $51 million in 2002), CCC asserts that ComEd's policies and practices were successful in steadily reducing its uncollectible expenses from 2000 through 2004. CCC argues that this downward trend is expected to continue as ComEd institutes stricter credit policies and implements internal risk scoring systems that are now part of ComEd's operating policies.*Id.*

In his direct testimony, Mr. McGarry presented the results of his analysis of a reasonable adjustment to the Company's uncollectibles expense:

Based on the Company's FERC Form 1, account 904, the uncollectible expense amount for 2003 and 2004 was $45,907,378 and $37,053,694 respectively. This represents a 19% reduction in the uncollectible expense. If the continued decline in uncollectibles is realized as ComEd references in their response to TEE 3.07, this amount should be reduced for this rate case. If we conservatively use a 14% decline, this would reduce the uncollectible expense to $9,380,364.

CCC Ex 2.0 at 24, L. 536-541.

In rebuttal testimony, Mr. McGarry supported Staff witness Ebrey's proposed 15% downward adjustment to the Company's uncollectibles expense. CCC avers that ComEd's current request represents a 33% increase over the 2004 uncollectibles rate. Mr. McGarry supported Ms. Ebrey's recommendation to use a five-year average rather than the test year ***246** amount for the calculation of the expense to be included in the Company's revenue requirement, because this approach is more consistent with the Commission's practice of normalizing expenses with high annual volatility. Moreover, it is a better indication of ComEd's actual uncollectible expense than the test year number and reflects the downward trend resulting from ComEd's collection efforts and credit policies. Although Ms. Ebrey's and Mr. McGarry's respective methodologies were developed in a slightly different manner, their ultimate conclusions are substantially similar (Mr. McGarry's initial recommendation was a 14% reduction, and Ms Ebrey's was a 15% reduction). CCC Ex 5.0 at 23, L. 453-457; Staff Ex. 2.0 at 26, L. 562-567. CCC concludes that the Commission should adopt Staff's proposal to reduce ComEd's uncollectibles expense by 15%; in the alternative, the Commission should adopt Mr. McGarry's adjustment and reduce uncollectibles by 14%.

Commission Analysis and Conclusion

****89** ComEd is proposing an uncollectible rate of

0.85% based on a customer class analysis of the 2004 test year. This proposal is an increase over the actual overall uncollectibles rate for 2004 of 0.64%. The Company argues their figures are more appropriate and accurate because they reflect the improved policies and practices for managing uncollectible expenses. Through stricter credit policies, implemented internal risk scoring systems and other system changes, ComEd total actual 2004 expenses are lower than 2003, 2002 and 2001.

Staff witness Ebrey proposed an adjustment based on a five year average that produces an uncollectibles rate of 0.72%. Staff argues that the 0.85% proposed by the Company is higher than the overall uncollectibles rate for every one of the last five years and is a 33% increase from the overall 2004 uncollectibles rate.

The CCC's witness McGarry noted that the Company's policies and practices were successful in reducing its uncollectible expenses from 2000 through 2004. He is proposing that this trend will continue and recommends a 14% decline or a 0.64% uncollectible rate. In the alternative, Mr. McGarry supports the .072% uncollectible rate proposed by Staff.

Staff's uncollectible rate is the same as ComEd's proposed overall uncollectibles as a percentage of base rate revenues. Furthermore, Staff has demonstrated that an increase to 0.85% is neither warranted nor supported by the historical data. Therefore, the Commission adopts the uncollectible rate of 0.72% as proposed by Staff. This adjustment reduces ComEd's revenue requirement by $1,988,000.00.

8. CHARITABLE CONTRIBUTIONS

ComEd

[44, 45] ComEd's revenue requirement includes charitable donations.*E.g.*, ComEd Ex. 5.1, Sched. C-2.4; Hill Reb., ComEd Ex. 19.0 Corr., 57:1269-75. ComEd notes that charitable contributions are an appropriate component of the revenue requirement. Section 9-227 of the Act, 220 ILCS 5/9-227 states that: ‘The Commission shall be prohibited from disallowing by rule, as an operating expense, any portion of a reasonable donation for public welfare or charitable purposes.‘

ComEd disputes Staff's proposed adjustment for ComEd's contribution of $50,000 to the Illinois Manufacturers' Association (the ‘IMA‘), based on Staff's conclusion regarding the primary purpose of the IMA. ComEd notes that its contribution was to the IMA's ‘Research on Education in Illinois‘ program, and thus is a charitable contribution. Hill Sur., ComEd Ex. 36.0 Corr., 46:1039-41.

Staff

Staff witness Dianna Hathhorn testified that an adjustment to remove contributions to certain community organizations from the Company's miscellaneous general expenses was necessary. Her testimony focused on the important fact that Company's participation in such groups is a promotional and goodwill practice, ***247** designed primarily to bring the Company's name before the general public in such a way as to improve the image of the utility or to promote utility industry issues. (ICC Staff Exhibit 12.0, Schedule 12.9) In her rebuttal testimony, Ms. Hathhorn modified her proposed adjustment to remove those organizations that ComEd subsequently substantiated as charitable contributions rather than memberships. (ComEd Ex. 19.0 Revised, pp. 56-57) Therefore, Ms. Hathhorn's final adjustment of $204,000 consists of two components.

****90** First, Ms. Hathhorn testified that her final adjustment includes those contributions which ComEd agreed should be removed, namely contributions to the Illinois Energy Association, the Metropolitan Club, the City of Chicago-Mayor's Office of Special Events, and the Illinois Business Roundtable. (ComEd Ex. 19.0 Revised, p. 57) Second, she stated that her final adjustment also includes the contribution to the Illinois Manufacturers Association (‘IMA‘), which ComEd continues to contest. Ms. Hathhorn's rebuttal testimony pointed out that the IMA invoice was clearly labeled a ‘Legislative Strategies‘ contribution, and her review of the IMA web site (www.ima-net.org) showed that the primary purpose of the organization is to monitor and influence legislation. Therefore, she concluded that ComEd's contribution must be disallowed from the revenue requirement, as Section 9-224 of the Act (220 ILCS 5/9-224) prohibits including in any rate or charge amounts expended for political activity or lobbying. (ICC Staff Exhibit 12.0, p. 16).

Commission Analysis and Conclusion

The only remaining dispute under Charitable Contributions is a $50,000.00 donation to the Illinois Manufacturers' Associations (IMA). ComEd claims that this contribution was for the IMA's 'Research on Education in Illinois' and that Staff's adjustment for this should be rejected. Staff argues that the invoice is clearly labeled a 'Legislative Strategies' contribution. Section 9-224 of the Act (220 ILCS 5/9-224) prohibits including in any rate or charge any costs or payments for lobbying or political activity. Therefore, the Commission accepts Staff's recommended disallowance of $50,000.00.

9. PROCUREMENT CASE EXPENSES

The discussion regarding the proper amount, and the proper recovery mechanism, of procurement and rate case expenses has been consolidated in Sections III.8-10 of this Order.

10. RATE CASE EXPENSES

See Section 9. above.

11. ENVIRONMENTAL EXPENSES

ComEd

See Section II.I.4 of this Order, *infra.* If Rider ECR is hereby approved without modification, no adjustment need be made to the test year revenue requirement.

Commission Analysis and Conclusion

Because the Commission amended ComEd's proposed Rider ECR to exclude non-MGP related expenses, $1,466,667 will be added back into the test year revenue requirement.

12. PSEG MERGER SAVINGS

ComEd

[46] ComEd observes that Exelon's proposed merger with Public Service Enterprise Group ('PSEG'), the parent company of Public Service Electric and Gas Company ('PSE&G'), a New Jersey electric and gas utility, has not yet been approved by state and federal authorities. ComEd also notes that while the merger is currently projected to close in mid-2006, even AG witness Mr. Effron agreed that that projected closure date is uncertain. Houtsma Reb., ComEd Ex. 18.0 Corr., 21:464-70, 20:438-42; Effron Dir., AG Ex. 1.0, 31:1-4; Effron, Tr. at 1594:19-1595:10. Moreover, ComEd states, ***248** even if the merger were to be approved in mid-2006, the earliest projection of any actual savings to ComEd from the merger is mid-2007. Houtsma Reb., ComEd Ex. 18.0 Corr., 22:483. ComEd adds that such projection does not take account of possible reductions to merger savings that could result from conditions on the merger that may ultimately be imposed by the 'BPU') or the Department of Justice, ('DOJ '). Houtsma Reb., ComEd Ex. 18.0 Corr., 21:458-61. Accordingly, ComEd points out that any projected savings from the merger would not occur within 12 months of the filing of the tariffs that initiated these proceedings (*i.e.* , by August 31, 2006), and are neither known nor measurable changes, nor changes determinable in amount, as would be required to meet the criteria of Section 287.40 of Part 287 for a *pro forma* adjustment to test year expenses. ComEd also observes that if the merger is closed, and savings achieved starting in 2007, those savings can be taken into account in determining ComEd's revenue requirement in the next rate case.

****91** ComEd identifies four independent reasons for rejecting AG witness Mr. Effron's assertion that ComEd's test year operating expenses be reduced by $20.561 million to reflect alleged annual merger 'savings,' which, ComEd claims, he derived from mathematical manipulations of ComEd's projections from the New Jersey proceeding

First, ComEd notes that even if the merger were to close by August 31, 2006, and even if it were assumed that the standards for projecting savings in the merger proceeding are the same as required by Section 287.40, there would be no valid basis for disregarding Exelon's estimates and substituting Mr. Effron's. ComEd notes that Exelon's estimates do not show any net merger savings until mid-2007, well beyond the cut-off date of August 31, 2006 for *pro forma* changes to test year costs.

Second, ComEd points out that Exelon's estimates of merger savings in the New Jersey proceeding in fact do not meet the standards of Section 287.40 for ratemaking purposes. ComEd states that the merger savings projected by Exelon are neither 'known and measurable' nor 'determinable', in part because the merger is currently subject to numerous regulatory approvals. Moreover, ComEd noted, even if the merger were approved, when the merger would be approved, whether there would be conditions imposed that impact the savings that could be realized, and when the savings would begin to be realized would all be uncertain. Houtsma Reb., ComEd Ex. 18.0 Corr., 21:452-61. In addition, ComEd argues that even if the merger were approved and closed in mid-2006, there would be a significant ramp-up period before any merger savings could be fully achieved and there would be significant up-front costs that would be incurred to achieve those savings. Thus, as noted above, ComEd observes that no net savings are projected for ComEd from the merger until at least mid-2007, well beyond August 31, 2006. Houtsma Reb., ComEd Ex. 18.0 Corr., 22:477-83. In addition, ComEd shows that over 70% of the expected net savings to ComEd from the merger would occur in 2008 and 2009. ComEd concludes that such far distant savings, which Mr. Effron's use of averaging makes appear will occur in 2006, even though they will not, are far outside the time period allowable for a *pro forma* adjustment. Houtsma Reb., ComEd Ex. 18.0 Corr., 21:467- 22:490.

Third, ComEd notes that if Exelon's merger savings estimates are not 'known and measurable' and 'determinable', Mr. Effron's are even less so, as he simply reduced Exelon's projections of expected four year gross savings by 50% to 'avoid disputes.' Characterizing this estimate as 'back of the envelope,' ComEd observes that such estimate on its face is ambiguous and uncertain, and is not based on any study or analysis presented in this proceeding of what is required to produce the savings. Houtsma Reb., ComEd Ex. 18.0 Corr., 23:498- 506. Moreover, ComEd notes that Mr. Effron conceded that even if the merger were to close before August 31, 2006, ComEd would not achieve the annual merger savings he projects of $20.6 million. Effron, Tr. at 1596:19-21, 1598:2-18, 1600:10-20. ComEd concludes that Mr. Effron had provided no estimate of the savings that would occur by August 31, 2006, and ***249** that absent that showing, his merger savings adjustment failed to meet the Section 287.40 requirement.

****92** Finally, ComEd observes that during the four-year period Mr. Effron testified is appropriate for estimating savings (Effron Dir., AG Ex. 1.0, 37 n.7), his proposed adjustment assumes total savings of $82,244,000, which is more than double Exelon's estimate of net savings to ComEd from the merger over this same period of $43.4 million. Houtsma Reb., ComEd Ex. 18.0 Corr., 22:477-83. Thus, ComEd notes, use of Mr. Effron's proposed estimate would lead to a cumulative revenue shortfall for ComEd over four years of almost $40 million, which would be both unfair and confiscatory.

AG

The AG notes that Exelon is in the process of securing approval from the relevant regulatory authorities to acquire PSEG, the parent company of PSE&G, a large electric and gas utility in New Jersey. Before the BPU, Exelon and PSE&G jointly presented forecasted merger savings allocable to regulated utility operations over the four-year period 2006-2009 of $154.6 million, or approximately $38.7 million per year. BPU Docket No. EM05020106.The AG asserts that, if the achievement of these savings were speculative or uncertain, then it would not have been appropriate for Exelon and PSEG to have presented the merger savings as a justification for approval of the merger before the BPU, and, assuming the merger occurs as planned, these savings are known and measurable. In accordance with this position, the AG's witness Effron allocated one half of the gross merger savings allocable to ComEd to ratepayers to allow ComEd to retain one half of the savings to cover costs incurred to achieve the merger savings. The effect of this allocation on the Company's revenue requirement was to reduce *pro forma* jurisdictional operational and maintenance expense by $20,561,000.

Commission Analysis and Conclusion

This issue concerns the proposed savings from the merger between Exelon and PSEG, the parent company of PSE&G, a large electric and gas utility in New Jersey. The Attorney General presented the testimony of Mr. Effron concerning the proposed savings from this merger. Mr. Effron reviewed the proposed projections submitted to the New Jersey Board of Public Utilities and he simply reduced Exelon's projections of expected four-year gross savings by 50%. He did not base that estimate on any study or analysis presented in this docket, and admitted that even if the merger were to close before August 31, 2006, ComEd would not achieve the annual merger savings he projected of $20.6 million. Mr. Effron admitted that these savings can only be ‘known and measurable‘ if the merger is approved by the New Jersey Board of Public Utilities. Given Mr. Effron's failure to provide an estimate of the savings that would occur by August 31, 2006, his proposed merger savings adjustment does not meet the Section 287.40 requirement.

There is far too much uncertainty surrounding the pending Exelon-PSEG merger to make an adjustment for any possible savings. Among other things, state and federal authorities have not approved the merger, its closure date is uncertain, the earliest projection of any actual savings is mid-2007, and there might be conditions placed on approvals. The Commission finds that any projected savings would not occur within 12 months of the filing of the tariffs that initiated these proceedings. The savings are not known or measurable changes, nor are the changes determinable in amount, as required by Section 287.40. Given the foregoing uncertainties, the Commission rejects the AG's proposed PSEG merger savings adjustment.

13. DEPRECIATION EXPENSE

ComEd

****93** ComEd's final revised revenue requirement correctly includes $321,002,000 of depreciation expenses. *E.g.*, Hill Sur., ComEd Ex. 36.0 Corr., Sched. 1 Rev., p. 1. ComEd indicates that the amount included in its filing for depreciation expenses is essentially the ‘return on‘ its capital ***250** investments to which ComEd is entitled.

ComEd indicates that the other parties' proposed adjustments to ComEd's depreciation expenses in this case are entirely derivative of their respective proposed adjustments to plant discussed in Sections II.C (several subsections) and II.D.6, *supra*. ComEd argues that because their underlying proposed adjustments to ComEd's plant balances are without merit, as discussed there, their entirely derivative adjustments to ComEd's depreciation expenses also are without merit.

Commission Analysis and Conclusion

Staff and various intervenors proposed adjustments to ComEd's plant figures in its proposed rate base. If accepted, these adjustments would affect ComEd' depreciation expense figure. As discussed elsewhere in this Order, many of the underlying adjustments to ComEd's rate base were not adopted. ComEd's approved depreciation expenses are and are reflected in the Appendix to this Order.

14. PAYROLL TAXES

Payroll taxes are derivative of ComEd's revenue requirement (and the approved adjustments thereto) and thus do not require a separate Commission finding. ComEd's approved payroll tax expenses are shown in the Appendix to this Order.

15. INCOME TAX EXPENSES

As with payroll taxes above, income taxes are derivative of ComEd's revenue requirement (and the approved adjustments thereto) and thus do not require a separate

Commission finding. ComEd's approved income tax expenses are shown in the Appendix to this Order.

16. GROSS REVENUE CONVERSION FACTOR

Staff

[47] Staff presented its gross revenue conversion factor ('GRCF') in ICC Exhibit 1.0, Schedule 1.6. Staff's GRCF is multiplied by the income deficiency to determine the total amount of revenue required for the income deficiency and the associated increase in income tax expense and uncollectible expense. It is based upon the applicable federal tax rate, state income tax rate, and Staff's uncollectible rate, sponsored by Staff witness Ebrey in ICC Staff Exhibit 2.0, Schedule 2.5. (For ComEd's, Staff's and CCC's discussion of the uncollectible rate, *see* Section V.G.)

Commission Analysis and Conclusion

The Gross Revenue Conversion Factor is multiplied by the income deficiency to determine the total amount of revenue required for the income deficiency and the associated increase in income tax expense and uncollectible expense. This formula was not contested by any party. It is based upon the applicable federal tax rate, state income tax rate, and the uncollectible rate. This is based on adjustments and conclusions discussed in other parts of this Order. The Gross Revenue Conversion Factor is and is reflected in the Appendix attached to this Order.

17. ADVERTISING EXPENSE ADJUSTMENT

ComEd

****94** ComEd agreed to Staff's proposed adjustment to remove $349,000 of advertising expenses from the revenue requirement, except ComEd and Staff agreed that the correct amount of the adjustment is $317,000. Hathhorn Dir., Staff Ex. 1.0, 18:370-19:389; Hill Reb. ComEd Ex. 19.0 Corr., 58:1286-96; Hathhorn Reb., Staff Ex. 12.0, 16:352-17:360. Accordingly, this issue is uncontested.

Commission Analysis and Conclusion

ComEd agreed to Staff's proposed adjustment to advertising expenses from the revenue requirement. Staff had originally proposed an ***251** adjustment of $349,000. ComEd and Staff agreed that the correct amount of the adjustment is $317,000. The Commission approves the proposed adjustment to remove $317,000 of advertising expenses from the revenue requirement, as being reasonable and appropriate.

18. STAFF 2005 SALARY AND WAGE ADJUSTMENT

ComEd

ComEd in its rebuttal testimony agreed to Staff's adjustment to remove $1,174,000 of ComEd's *pro forma* salary and wage increases adjustment for 2005. Ebrey Dir., Staff Ex. 2.0, 30:627-35; Hill Reb., ComEd Ex. 19.0 Corr., 42:931-37.

Commission Analysis and Conclusion

ComEd agreed to Staff's adjustment to remove $1,174,000 of ComEd's *pro forma* salary and wage increases adjustment for 2005. Therefore, the Commission approves Staff's proposed adjustment as reasonable and appropriate.

19. CONTINGENCY PAYMENTS TO TAX CONSULTANTS

ComEd

[48] The AG in its direct testimony suggested an adjustment to remove a $4,600,000 charge for payments to tax consultants in 2004. Effron Dir., AG Ex. 1.0, 35:7-36:2. In order to narrow the issue. ComEd in its rebuttal testimony agreed to make the adjustment. Hill Reb., ComEd Ex. 19.0 Corr., 48:1058-63.

AG

The AG's witness Effron eliminated a charge related to ComEd's payment of tax consultants, because the Company did not establish that the tax refunds obtained by hiring tax consultants were of any benefit to ratepayers. ComEd witness Hill agreed to incorporate the AG's witness Effron's reduction to operation and maintenance expense by $4,460,000 to account for his elimination of that charge.

Commission Analysis and Conclusion

The AG, in its direct testimony, suggested an adjustment to remove a $4,460,000 charge for payments to tax consultants in 2004. The AG pointed out that there was no ratepayer benefit to this payment. ComEd, in its rebuttal testimony, agreed to make the adjustment. Therefore, the proposed adjustment to remove a $4,460,000 charge for payments to tax consultants in 2004 is hereby approved.

20. EMPLOYEE ARBITRATION SETTLEMENTS

ComEd

[49] ComEd, in light of the AG's position, in order to narrow the issues, proposed to reduce ComEd's test year employee settlement/arbitration costs by $4,301,224 to account for a true-up credit booked in 2005. Hill Reb., ComEd Ex. 19.0 Corr., 47:1026-48:1056. ComEd noted that the AG agreed to the revised adjustment.

AG

In an effort to limit issues in this proceeding, AG's witness Effron adopted ComEd's adjustment of $4,301,000 to jurisdictional test year employee settlement/arbitration expense.

Commission Analysis and Conclusion

****95** ComEd and the AG agreed to a proposed adjustment. The proposed adjustment to reduce ComEd's test year employee settlement/arbitration costs by $4,301,224 to account for a true-up credit booked in 2005 is hereby approved by the Commission.

21. WEATHER NORMALIZATION

ComEd

***252 [50]** ComEd states that there is no material contested issue on this subject at this time.

AG

The AG asserts that ComEd selectively employed weather normalized data to calculate revenues under present rates. Specifically, the AG state that ComEd used weather-normalized billing determinants to design the rates that will result in the required revenues, but did not weather-normalize the actual test year revenues for the purpose of calculating *pro forma* test year operating income under present rates. This unbalanced application of weather normalized data does not provide an accurate picture of test year revenues.

Therefore, the AG's witness Effron adjusted *pro forma* test year operating revenues under present rates to reflect the weather normalization of actual test year billing determinants. This adjustment increases test year revenues by $32,796,000. This increase to revenues reduced the Company's revenue deficiency but did not affect the Company's revenue requirement and should not affect the rate design.

Commission Analysis and Conclusion

The Company employed a weather normalized amount of test year billing determinants to calculate revenues under present rates. Specifically, ComEd uses weather-normalized billing determinants to design the rates that will result in the required revenues. According to the AG, ComEd does not weather-normalize the actual test year revenues for the purpose of calculating *pro forma* test year operating income under present rates. This unbalanced application of weather normalized data does not provide an accurate picture of test year revenues.

The AG's witness, Mr. Effron adjusted *pro forma* test year operating revenues under present rates to reflect the weather normalization of test year billing determinants. This adjustment increases test year revenues at present rates by $32,796,000. This increase to revenues reduces the Company's revenue deficiency but does not affect the Company's revenue requirement and should not affect the rate design. ComEd indicated that there is no material contested issue on this subject at this time. Therefore, this proposed adjustment is approved by the Commission.

22. INCREASE IN NON-DST REVENUES

ComEd

[51] ComEd explains that in this case, 'non-DST' revenues shown in its Schedules are those revenues of ComEd that are not attributable to an Illinois-jurisdictional delivery services tariff and are not miscellaneous revenues (or part of the 'new business' revenue credit). ComEd presented evidence that such revenues totaled $3,883,066,000 for 2004.*E.g.* Hill Reb., ComEd Ex. 19.0 Corr., 5:101-6:127, ComEd explains that BOMA witness Michael McClanahan erred in asserting that ComEd had not justified its non-DST operating revenues (McClanahan Dir., BOMA Ex. 2.0, 4:83-6:123), and why his assertion should be rejected. ComEd also explains that such revenues are only a presentation item that does not affect the revenue requirement. Hill Reb., ComEd Ex. 19.0 Corr., 5:101-8:156. ComEd notes that Mr. McClanahan did not respond to these explanations in his rebuttal testimony.

****96** *Commission Analysis and Conclusion*

The record shows that ComEd's non-DST operating revenues of $3,883,066,000 are properly calculated. The Commission notes that only one party - BOMA - raised a question about these revenues, and once ComEd addressed that question, BOMA did not pursue the issue any further. The Commission therefore concludes that such revenues, as calculated by ComEd, are appropriate, and that, in any event, they are only a presentation issue that does not affect the revenue requirement.

23. APPROVED OPERATING EXPENSES AND REVENUES

***253 [52, 53]** Based on the electric utility delivery services operating expense statement as originally proposed by ComEd and the adjustments to operating revenues and expenses as summarized above, the total electric utility delivery services operating expenses for ComEd approved for purposes of this proceeding are $1,084,041,000. The operating expense statement may be summarized as follows:

Approved Operating Expense Statement	
(In Thousands)	
Operating Revenues	$1,585,997
Other Revenues	95,149
	____
Total Operating Revenue	1,681,146
Uncollectibles Expense	11,536
Distribution	270,239
Customer Accounts	128,119
Customer Services and Informational Services	8,135
Sales	0
Administrative and General	193,822
Depreciation and Amortization	320,951
Taxes Other Than Income	145,556

Regulatory Debits	5,683
	____
Total Operating Expense Before Income Taxes	1,084,041
State Income Tax	25,731
Federal Income Tax	43,363
Deferred Taxes and ITCs Net	85,750
	____
Total Operating Expenses	1,238,885
Net Operating Income	$442,261
	=

The development of the overall electric utility delivery services operating expense statement adopted for purposes of this proceeding is shown in the Appendix to this Order.

V. RATE OF RETURN

1. CAPITAL STRUCTURE

ComEd

[54] ComEd stated that its capital structure contains common equity and long-term debt as its sources of capital. ComEd proposed to use its actual capital structure, after a *pro forma* adjustment to remove a one-time fair value step-up in equity that occurred due to the merger accounting, and a measurement period ending June 30, 2005. Mitchell Dir., ComEd Ex. 7.0, 6:118-23. ComEd contends that this capital structure reflects the actual adjusted 54.20% equity and 45.80% debt and is based on ComEd's actual audited book balances of debt and equity. ComEd Ex. 7.1, Sched. D-1. ComEd opines that such actual capital structure - together with the percentage costs of debt and equity discussed *infra* - define the actual cost that ComEd incurs in attracting and maintaining the capital that ComEd uses for its only current business: to purchase, operate, and maintain its delivery facilities and to provide delivery service with them.

ComEd argues that its actual capital structure is reasonable. ComEd witness Mitchell states, among other things, that such structure was chosen for sound business reasons; was comparable to previously approved capital structures and the capital structures of other financially sound utilities; and results in reasonable credit metrics. Mitchell Dir., ComEd Ex. 7.0, 5:91-103, 7:144-8:156; Mitchell Sur., ComEd Ex. 37.0 2nd Corr., 19:383-21:412, 15:313-17:340. In addition, witness Mitchell argues that its management carefully considers its levels of debt and equity and has managed the capital structure to maintain a reasonable A-credit rating. Mitchell Reb., ComEd Ex. 20.0, 2:26-29, 3:49-9:192; Mitchell Sur., ComEd Ex. 37.0 2nd Corr., 8:157-75. ComEd also claims that it has consistently maintained a level of equity consistent with both past equity balances and the need to maintain a level of equity sufficient to maintain financial strength when risks inevitably materialize. Mitchell Sur., ComEd Ex. 37.0 2nd Corr., 17:341-45. ComEd claims that no party disputed the proof of its 54/46 capital structure, the actual equity and debt balances on its books from which it was derived, or the appropriateness of the measurement period ComEd used. ComEd also says that no ***254** witness testified that an A- credit rating is *per se* unreasonable, or that ComEd's liability management program, which reduced the amount of outstanding debt, was imprudent. Nor, ComEd says, did any witness testify that, historically, ComEd had too much equity or that it is unreasonable for ComEd to maintain a $5.194 billion equity balance. Indeed, ComEd states, capital structures consistent with a strong credit rating have been approved for ComEd in each of its last three rate cases.*Commonwealth Edison Co.*, ICC Docket 94-0065 (Final Order, January 9, 1995); *Commonwealth Edison Co.*, ICC Docket 99-0117 (Final Order, August 26, 1999); *Commonwealth Edison Co.*, ICC Docket 01-0423, 224 P.U.R. 4th 357, 336-37 (Final Order, March 28, 2003).

****97** ComEd argues, however, that Staff, CCC, IIEC, and the AG nonetheless proposed artificial capital structures with much greater leverage than either ComEd or similar utilities actually have.*See,e.g.*, Kight Dir., Staff Ex. 4.0 Corr., 4:74-6:112; Gorman Dir., IIEC Ex. 3.0 Corr, 14:322-25, 18:416-22; Bodmer Dir., CUB/CC-SAO Ex. 1.0 2nd Corr., 20:597- 22:649. ComEd opines that such proposals understate ComEd's actual capital costs. ComEd witness Hadaway believes that this 37.19% equity/62.81% debt capital structure introduced by Staff (the ‘37/63 capital structure‘) would deny ComEd recovery of more than $74 million in costs each and every year. Dr. Hadaway added that even if the 37/63 capital structure were not a wholly unrealistic capital structure for ComEd, a company that could support such a capital structure would have a very different cost of equity, a difference that is completely ignored by Staff, CCC, IIEC, and the AG. Hadaway Sur., ComEd Ex. 38.0, 2:30-39 (when leverage increases, the cost of equity increases). ComEd asserts that this result would be confiscatory and, as discussed further below, not sustainable.

ComEd also argues that the record does not support either the purported reason for rejection of ComEd's actual capital structure or the use of a radical artificial replacement. ComEd asserts that the law on recognizing utility capital structures is clear. ComEd argues its entitlement to manage its own business affairs (*Public Utilities Commission v. Springfield Gas Co.*, 291 Ill. 209, 218-19 (1920); *Iowa-Illinois Gas & Electric Co. v. Illinois Commerce Comm'n.*, 19 Ill. 2d 436, 442 (1960)), including choosing its own reasonable capital structure. ComEd further argues that, to disturb a utility's capital structure, it is necessary that the actual capital structure be proven to be unreasonable - which cannot be accomplished by simply suggesting that another capital structure is reasonable, or that another structure might be ‘optimal‘ or ‘lower cost‘.*People ex rel. Hartigan v. Illinois Commerce Commission*, 214 Ill. App. 3d at 222:227-28 (3rd Dist. 1991).

ComEd argues the advocates of the 37/63 capital structure for ratemaking purposes never advocated that ComEd actually issue debt sufficient to become financed by 63% debt. Gorman, Tr. at 2004:2-2005:4. ComEd also argues that the direct testimony of IIEC witness Gorman strongly advocates a hypothetical 50/50 capital structure, which in ComEd's opinion both comports with past Commission Orders and can be reconciled with the leverage ratios of ComEd's peers. Gorman Dir., IIEC Ex. 3.0 Corr., 16:363- 72. ComEd further states that, although Mr. Gorman ultimately supports the 37/63 capital structure, he did not repudiate his earlier testimony about the reasonableness of a 50/50 capital structure.

ComEd argues that the 37/63 capital structure is not reasonable. ComEd opines that such leverage ratio is far outside that of typical utilities and is higher than any comparable company included in Staff's own sample of comparable companies. Mitchell Sur., ComEd Ex. 37.0 2nd Corr., 18:362-20:394. ComEd also contends that Staff's claim that a capital structure with 37% equity is consistent with a range of financially sound utilities is undermined by the improper inclusion of the non-profit and functionally unregulated cooperative, Old Dominion Electric. ComEd witness Mitchell testifies that when Old Dominion is excluded, ‘all of the remaining utilities have common equity ratios of at least 41.6% and two had common equity ratios in excess of 60%. None of the remaining companies had common equity ratios nearly as ***255** low as the 37.11% ….‘ Mitchell Sur., ComEd Ex. 37.0 2nd Corr., 6:120-23. Mr. Mitchell further argues that, Mr. Bodmer's similar efforts actually rely on companies with lower credit ratings and distort the overall conclusion that ‘despite [the] relatively weak S&P bond ratings [of the companies he cites], all but five of which have ratings below ‘A-,‘ the average of the common equity ratios for the 25 electric companies was 48%.‘*Id.*, at 10:208-11:210.

****98** In its testimony ComEd maintains that the Unicom/PECO merger and the transfer of the former ComEd nuclear assets were two distinct transactions, separated by months, separately authorized by the Act, and separately reviewed by the Commission. ComEd contends that it fully adjusted for the $2.292 billion effect of the merger accounting on its equity balance, fully removing that amount from equity in its 54/46 capital structure. Mitchell Reb., ComEd Ex. 20.0, 13:262-16:334; Mitchell Sur., ComEd Ex. 37.0 2nd Corr., 12:238-15:305; Houtsma Reb., ComEd Ex. 18.0 Corr., 25:543-27:591; Houtsma Sur, ComEd Ex. 35.0, 16:352-23:510; Kight, Tr. at 1827:6-21.

ComEd argues that other parties' claims that ComEd's equity should be reduced further is not about the effect of the merger itself, but about the value at which ComEd's former nuclear assets were transferred more than five years ago. ComEd states that the fact that the merger required the write down of the assets to their fair value is not in question. Rather, ComEd argues, the claim is that when the assets were transferred some time thereafter, instead of being transferred at their then current - and actual - book value, they should have been written up to their prior ‘original cost.‘ According to ComEd this claim is based on faulty assumptions - it is contrary to the record, is contrary to past Commission determinations of ComEd's capital structure and equity balance, and seeks both an unlawful second review of the long-completed transfer transaction and an illegal result.

First, ComEd argues that the transfer of the nuclear assets and the resulting effect on ComEd's equity balance, capital structure, and delivery rates have all been reviewed by the Commission in several prior Commission proceedings. ComEd states that it transferred its nuclear assets under the authority Section 16-111 of the Act. ComEd contends the transfer, its terms and structure, and its effect on ComEd's equity were all addressed in the Commission's Section 16-111 proceeding that reviewed the transfer; and the transfer was accomplished in accordance with the law, and with the Commission's determination in the notice proceeding dealing with the transfer. ComEd went on to state that the law required that the accounting be in accordance with GAAP, and GAAP required that the assets be transferred at book value at the time of the transfer ComEd also claims that the accounting entries - including the effect on equity - resulting from the transfer were both described to the Commission in advance and submitted when finalized. Houtsma Sur., ComEd Ex. 35.0, 3:56-58, 17:372-18:391.

ComEd argues that retroactive review of the transfer is unlawful and expressly prohibited by Section 16-111(g) of the Act. ComEd further argues that the Commission found that the nuclear unit transfers are covered by this prohibition of Section 16-111.*Commonwealth Edison Co.*, ICC Docket No. 05-0159 (Order Jan. 24, 2006) (the ‘Procurement Order‘) at 51.

****99** In addition, ComEd states that the Commission also considered ComEd's equity balance and established the proper post-merger and post-transfer capital structure for ComEd in ComEd's last delivery services rate case (ICC Docket No. 01-0423). In ComEd's opinion the Commission's decision in that rate case established a capital structure for ratemaking, without any reduction to ComEd's equity based on any notion that the nuclear assets had to be, or should have been, transferred at original cost rather than at book value.*Commonwealth Edison Co.*, ICC Docket No. 01-0423, (Int. Order, April 1, 2002) (‘01-0423 Interim Order‘), at 112 & App. A at Sched. 1 ComEd also argues that although Staff proposed other adjustments, not relevant here, throughout the proceeding it steadfastly recommended that ComEd's capital structure and equity balance, for ratemaking purposes, be based on its actual book equity ***256** balance. Kight, Tr. at 1840:21-1842:17, *quoting* , in part, J. Freetly (Staff) Dir., *Commonwealth Edison Co.*, ICC Docket No. 01-0423 Staff, Ex. 5.0, at 9:143-46.

ComEd also argues that the Commission's determination in Docket 01-0423 was wholly inconsistent with the equity balance that proponents of the 37/63 capital structure ask the Commission to use now. ComEd asserts that, in Docket 01-0423, the Commission found that ComEd's equity balance as of the end of 2001 was $5.224 billion, a value very similar to the current equity balance, and that this equity balance should be used in deriving the approved rates. ComEd states, however, that no witness here testified that there was any way to reconcile the $5.224 billion Commission-approved equity balance with the $2.561 billion equity balance the 37/63 capital structure now requires. Mitchell Reb., ComEd Ex. 20.0, 7:141-50; Kight, Tr. at 1841:9-1842:14. [FN13] Indeed, ComEd offers, the events of the past five years suggest that ComEd's equity balance would, if anything, be equal or higher than the 2001 balance the Commission approved. Mitchell Reb., ComEd. Ex. 20.0, 5:100-6:122, 7:141-50.

Second, ComEd states that the transfer of ComEd's nuclear assets at a book value reflecting the fair value write-down was mandated by GAAP and expressly authorized, for Illinois law purposes, by Section 16-111(g) of the Act. ComEd maintains that the record is clear that the nuclear assets were properly written down and lawfully transferred, and that GAAP requires that transfer to occur at book value. Houtsma Sur., ComEd Ex. 35.0, 17:372-18:391. In contrast, ComEd claims that the record also is clear, that the equity balance implied by the 37/63 capital structure is inconsistent with GAAP and ComEd's audited financial statements. Houtsma Sur., ComEd. 35.0, 17:374- 18:391; Kight, Tr. at 1819:23-1825:17.

Third, ComEd contends that the proponents of the 37/63 capital structure assume, without evidence, that, had ComEd been required to transfer the assets at value (billions of dollars above book), it still would have structured the transfer in exactly the same way. Houtsma Sur., ComEd. Ex. 35.0, 18:386-89. ComEd claims that once the value of the plants is assumed to be different by billions of dollars, there is no basis in logic, fairness, business judgment, or common sense for assuming that the value is the only element of the transaction that would have changed. Mitchell Sur., ComEd Ex. 37.0 2nd Corr., 13:270-15:305. ComEd further argues that the 37/63 capital structure becomes even less plausible when the resulting impact on equity is considered: ComEd claims it has consistently managed its capitalization to achieve an equity balance above $5 billion, yet the equity balance that would have resulted from a transfer where nothing but the value is changed would be inconsistent with that practice. ComEd asserts that this is important, given that ComEd could have avoided the impact on equity by structuring the nuclear asset transfer differently. Kight, Tr. at 1835:1- 22. In addition, ComEd argues that the notion that any increase in the assumed value of the plants should only reduce ComEd's equity is further belied by the original financing of the plants, which involved both debt and equity. Houtsma Surr., ComEd Ex. 35.0, 17:374- 18:391; Kight, Tr. at 1836:9-16.

****100** ComEd claims that there are several flaws with IIEC claims that a deduction must be made from equity because rate base does not closely correspond to total capitalization, and that ‘goodwill‘ does not ‘support‘ the provision of delivery service. For instance, ComEd claims that there is no reason that rate base and capital structure should match, or even be close in value. As an example, ComEd refers to Docket 01-0423, where the net rate base was less than 29.4% of the capital structure.*Commonwealth Edison Co.*, ICC Docket No. 04-0423 (Interim Order, April 1, 2002) at 112; *Commonwealth Edison Co.*, ICC Docket No. 04-0423 (Amendatory Interim Order, April 10, 2002), at 2, Finding (5). ComEd contends that numerous factors cause capital structure - a current, largely market-based construct, that is altered by the cumulative retained earnings, dividends, capital contributions, and refinancings - and rate base - a largely historical concept, derived from depreciated original cost - to diverge, ***257** and total capitalization may properly be more than, equal to, or in some cases even less than rate base.

ComEd argues that if equity ‘supports‘ goodwill as Mr. Gorman suggests, it does so only in the most trivial sense that if goodwill is impaired, equity is reduced. ComEd claims that ‘goodwill‘ requires no payments and uses no cash, and that no portion of ComEd's capitalization is sequestered to support the business of ‘maintaining goodwill.‘ ComEd argues that its entire capital structure - including all of its equity and debt - supports its utility business.

ComEd claims that Staff's and IIEC's arguments about TFI debt are red herrings. ComEd states that it proposed its actual capital structure, with no artificial adjustment for TFIs and no reliance on any such adjustment to support its capital structure. ComEd claims that the notion that the rating agencies will view 37% equity as ‘really‘ 45% simply because they will ignore TFIs when calculating debt ratios is incomplete and flawed. ComEd offers that if the agencies choose to back out the TFIs for debt ratio purposes, they will also back out the revenues required to pay TFI interest and retire the TFIs. Mr. Mitchell testified that if the Commission were to view the 37/63 capital structure as one that might be somehow magically less leveraged by simply disregarding the TFI balances and forbidding their 'replacement' by other debt, it could not ignore the fact that such a fictional TFI-less ComEd would also have considerably less revenue and would be, in fact, a weaker - not stronger - company. Mitchell Sur., ComEd Ex. 37.0 2nd Corr., 22:439- 23:453.

Moreover, ComEd argues, defending use of an artificial capital structure for setting rates that will not be charged until 2007 with an argument that the rating agencies will ignore TFI debt quantified in terms of its 2005 balances introduces yet another fiction. As ComEd contends, TFIs are temporary. they are rapidly shrinking in amount, will be gone by the end of 2008, and will be much diminished well before the proposed rates even go into effect (Kight, Tr. at 1817:19-1818:15) - and rating agencies are well aware of these facts.

Staff

****101** Staff and the Company agree that short-term debt should not be included in the capital structure since it is not currently financing rate base investments. In addition, Staff and the Company agree that ComEd's balance of preferred securities is zero. (ICC Staff Ex. 4.0 Corrected, p. 11) However, Staff and the Company disagree as to the balance and cost of long-term debt and common equity. While the Company proposes using an adjusted June 30, 2005, capital structure that contains 45.80% long-term debt and 54.20% common equity, Staff witness Ms. Sheena Kight recommends an adjusted capital structure containing 62.89% long-term debt and 37.11% Common Equity. (ICC Staff Ex. 4.0 Corrected, pp. 4-11, Schedule 4.1; ICC Staff Ex. 15.0 2nd Corrected, pp. 3-4)

Staff offers that the primary dispute with regard to capital structure involves differing views on the appropriate adjustment to ComEd's June 30, 2005, equity balance given (1) the increase in common equity resulting from the Company's use of purchase accounting to record the 2000 merger of PECO Energy Company and Unicom Corporation (ComEd's corporate parent at the time of the merger) and (2) ComEd's subsequent transfer of its generating assets to an affiliate in 2001 at the restated value of those assets resulting from the application of purchase accounting. (*See* ICC Staff Exhibit 4.0 Corrected, pp. 4-6) The second area of dispute is whether Staff's adjusted capital structure is an appropriate and reasonable capital structure. Staff asserts that its proposed capital structure incorporates necessary and appropriate adjustments to ComEd's June 30, 2005, equity balance, represents an appropriate and reasonable capital structure for ComEd, and should be adopted by the Commission.

Staff's Additional Adjustments to ComEd's Actual Balance of Common Equity

Staff states that ComEd's proposed capital structure is based on its June 30, 2005 capital structure adjusted to exclude $2.292 billion of ***258** equity that resulted from the application of purchase accounting for the Unicom/PECO merger. (*See* ComEd Ex. 7.0, pp. 2, 6) Staff states that pursuant to purchase accounting, ComEd's assets and liabilities were restated to their fair values as of the merger date, and the difference between the purchase price and the restated fair value of its assets and liabilities was recorded as goodwill. (*Id.*, p. 6) Staff offers that the net effect of these purchase accounting entries was a $2.292 billion increase in ComEd's equity balance. (*Id.*;*see also* ICC Staff Exhibit 4.0 Corrected, pp. 4-5) ComEd witness Mr. Mitchell provided the following summary of the purchase accounting entries that resulted in the $2.292 billion increase in ComEd's equity balance:

($millions)

Description	Increase/ (Decrease) in Equity
Plant Write Downs	($4,791)
5p	
Deferred Taxes and ITCs	2,157
5p	
Pension, OPEB and Severance	144
5p	
Other Assets, Liabilities and Long Term Debt	77
5p	
Goodwill (net of amortization)	4,705
	———
5p	
Net Increase in Equity	$2,292
	=

****102** (ComEd Ex. 7.0, p. 7) Staff states that according to Mr. Mitchell all of these entries, including goodwill, were excluded from the common equity balance reflected in ComEd's proposed capital structure. (*Id.*;*see also* ICC Staff Exhibit 4.0 Corrected, pp. 4-6)

Staff witness Ms. Kight reviewed ComEd's proposed common equity adjustments and, although she agreed in general that adjustments were necessary, she disagreed with certain aspects of ComEd's proposed adjustments. Since rates are based on original cost rate base, Ms. Kight contends that capital structure should also reflect the amount of capital originally invested in a utility's assets (assuming that capital structure is reasonable from a cost standpoint), not reassessments of the fair value of the capital invested. (ICC Staff Exhibit 4.0 Corrected, p. 5) Thus, Ms. Kight states that ComEd's June 30, 2005, capital structure, which reflects estimates of fair value for financial reporting purposes, should be adjusted to reflect depreciated original cost. (*Id.*) Staff argues that ComEd's actual capital structure for financial reporting purposes should be adjusted to the extent that purchase accounting and other entries have caused its actual capital structure to no longer reflect the capital supporting its depreciated original cost rate base.

Ms. Kight opposes the elements of ComEd's adjustments related to utility plant that it no longer owns (primarily reversal of the write downs of utility plant - subsequently transferred - made to restate those assets at their estimated fair value pursuant to purchase accounting). According to Ms. Kight the deferred taxes and ITC's written down were largely, if not wholly, associated with that utility plant. (ICC Staff Exhibit 4.0 Corrected, p. 5) In Ms. Kight's opinion such reversals might be appropriate adjustments to ComEd's capital structure if it still owned that utility plant or had received (and retained) as compensation assets equal to the pre-write down value for that plant. (ICC Staff Exhibit 4.0 Corrected, p. 5) However, she states, ComEd neither owns the plant assets that were written down nor received any assets in exchange. (*Id.*) Ms. Kight says that instead, ComEd transferred that plant to an affiliate at its estimated fair value (*i.e.*, at its written down value) as a capital contribution, which did not produce any proceeds for ComEd (receiving treasury stock instead).(*Id.*;*see also* Staff Cross Ex. 14, pp. 97-98; Staff

Cross Ex. 15, Item 5 - Other Events)

Staff argues that ComEd's transfer of its generation assets distorted the relationship between its actual capital structure and the capital supporting its depreciated original cost rate base. Staff claims the generation assets ComEd transferred had an original cost book value of approximately $6.7 billion. (ICC Staff Cross Ex. 15, Item 5 - Other Events; Tr., p. 2465) Staff submits that because these generating stations***259** and related liabilities were transferred at their restated fair value cost basis (approximately $2 billion) and all goodwill remained on ComEd's books, ComEd's actual capital structure necessarily continues to reflect the difference between (1) the original cost value of the assets and liabilities transferred and (2) the fair value cost of those same assets and liabilities (notwithstanding that ComEd no longer owns these assets). Staff argues that because those assets were not transferred at their book value and all goodwill remained on ComEd's books, ComEd's resulting actual capital structure was not reduced commensurate with the original cost book value of the assets and liabilities transferred.

****103** Ms. Kight argues that notwithstanding ComEd's reversal of the purchase accounting adjustments, its proposed capital structure does not reflect the amount of capital originally invested in ComEd's remaining assets. (*Id.*) Ms. Kight offers that ComEd's proposed capital structure overstates the amount of capital in use. (*Id.*) Ms. Kight states that ComEd's proposed $2.292 billion adjustment to common equity inappropriately includes the reversal of both write down of plant that ComEd no longer owns and the associated reduction to deferred income taxes and ITC's. (*Id.*, pp. 5-6) Accordingly, Ms. Kight states that ComEd's balance of common equity should be reduced by an additional $2.634 billion (the net effect of excluding ComEd's reversal for the $4.791 billion plant write down less the $2.157 billion reduction to deferred income taxes and ITC's).(*Id.*, p. 6) Ms. Kight claims removal of the adjustments associated with the transferred utility plant from ComEd's proposed capital structure results in a capital structure based on the unrecovered portion of the original investment in ComEd's *remaining* assets.

Reasonableness of Staff's Adjusted June 30, 2005 Capital Structure

Ms. Kight assessed whether it was appropriate to use Staff's adjusted capital structure to determine ComEd's overall rate of return. Ms. Kight states that financial theory suggests capital structure affects the value of a firm and, therefore, its cost of capital, to the extent it affects the expected level of cash flows that accrue to outside parties (*i.e.*, other than debt and stock holders). Ms. Kight went on to state that employing debt as a source of capital reduces a company's income taxes, thereby reducing the cost of capital; however, as reliance on debt as a source of capital increases, so does the probability of default. As default become more probable, expected payments to attorneys, trustees, accountants and other outside parties increase. Further, cash flows decline as the company is forced to forego opportunities otherwise available to it had its financial condition been stronger, including the expected value of the income tax shield provided by debt financing. Ms. Kight argues that beyond a certain point, a growing dependence on debt as a source of funds increases the overall cost of capital. Therefore, Ms. Kight opines, the Commission should not determine the overall rate of return from a utility's actual capital structure if the Commission concludes that capital structure adversely affects the overall cost of capital. (ICC Staff Exhibit 4.0 Corrected, pp. 6-7)

Ms. Kight further testifies that an optimal capital structure would minimize the cost of capital and maintain a utility's financial integrity. However, she states, determining whether a capital structure is optimal remains problematic because (1) the cost of capital is a continuous function of the capital structure, rendering its precise measurement along each segment of the range of possible capital structures problematic; (2) the optimal capital structure is a function of operating risk, which is dynamic; and (3) the relative costs of the different types of capital vary with dynamic market conditions. Consequently, Ms. Kight explains that one should determine whether a proposed capital structure is consistent with the financial strength necessary to access the capital markets under most conditions, and if so, whether the cost of that financial strength is reasonable. (*Id.*) To make these determinations, Ms. Kight compares Staff's proposed adjusted capital structure as of June 30, 2005 to utility benchmarks.

****104** Ms. Kight says that Standard & Poor's ***260** (‘S&P‘) categorizes debt securities on the basis of the risk that a company will default on its interest or principal payment obligations. She states the resulting credit rating reflects both the operating and financial risks of a utility. She further offers that although no formula exists for determining a credit rating, S&P publishes utility benchmark values, by business profile score, for financial ratios it uses to determine credit ratings. According to Ms. Kight S& P currently assigns ComEd a corporate credit rating of BBB+ and a business profile score of 4. Ms. Kight compares the values for those benchmark financial ratios that result from combining Staff's proposed adjusted capital structure with components from Staff's proposed revenue requirement to S&P's benchmarks for utilities with an A or BBB credit rating and a business profile score of 4. Ms. Kight testifies that according to S&P, utilities with a business profile score of 4 should have a funds from operation (‘FFO‘) to interest coverage (‘FFOIC‘) ratio between 3.5X and 4.2X for an A-rating and 2.5X to 3.5X for a BBB-rating. The benchmark ranges for the FFO to total debt (‘FFO/Debt ‘) coverage ratio is 20%-28% for A-rated utilities and 12%-20% for BBB-rated utilities. Ms. Kight further testified that Staff's proposed adjusted capital structure results in a FFO to interest coverage ratio of 3.78X, which is indicative of an A credit rating, and a FFO to total debt coverage ratio of 18.04%, which is indicative of a BBB credit rating. [FN14] Thus, Ms. Kight claims that Staff's proposed adjusted capital structure is indicative of a level of financial strength that is commensurate with at least a BBB credit rating. (ICC Staff Exhibit 4.0 Corrected, pp. 7-8 (emphasis added)) Ms. Kight further testified that a BBB credit rating is indicative of an adequate degree of financial strength. A credit rating of BBB indicates an adequate capacity to meet financial commitments. She also offered that a debt issuer with a BBB credit rating has access to debt capital under most, if not all, financial market conditions while taking greater advantage of the tax-deductibility of debt interest than capital structures that support higher credit ratings. (ICC Staff Exhibit 4.0 Corrected, p. 10)

Staff also asserts that under its proposal ComEd's FFO/Debt ratio falls in the top third of the BBB range and its FFOIC ratio is in the middle third of the A range. Staff contends that together the two ratios indicate that its proposed rates are sufficient to support financial strength that is commensurate with a credit rating of ‘A-‘ and is therefore consistent with the ‘A-‘ credit rating that the Company purports to target. (ICC Staff Exhibit 15.0 2nd Corrected, pp. 2-3) Table 1 presents the coverage ratios for the financial guidelines for the business profile ‘4‘ as well as those resulting from Staff's proposed capital structure and capital costs and ComEd's proposed capital structure and capital costs.

	AA	A	BBB			
Financial Guideline						
Ratios FFOIC	4.2-5X	3.5-4.2X	2.5-3.5X FFO/Debt	28-35%	20-28%	12-20%
Staff Proposal FFOIC		3.78X FFO/ Debt			18.04%	
ComEd Proposal FFOIC	5.42X FFO/ Debt	28.62%				

****105** Staff submits that Table 1 also illustrates that ComEd's proposed capital structure results in ratios that are commensurate with an ‘AA‘ credit rating, instead of the 'A-' credit rating ComEd professes to target. (ICC Staff Ex. 15.0 2nd Corrected, pp. 2-3, ComEd Ex. 20.0, p. 6)

Ms. Kight chose not to use a direct measure of capital structure such as the debt to total capital ratio ('debt ratio') because in Ms. Kight's opinion the debt ratio is less important in determining credit ratings. Staff asserts that unlike the FFO interest coverage and FFO to total debt ratios, the debt ratio neither reflects the cost of a company's debt nor the cash flows available to meet its debt service obligations. Staff also observes that the amount of debt in ComEd's capital structure includes Transitional ***261** Funding Notes ('TFNs', also known as Transitional Funding Instruments or 'TFIs'). (Tr. p. 1845) Staff claims the rating agencies exclude TFNs when assessing ComEd's financial risk and credit rating financial metric calculations. (IIEC Exhibit 7.0, p. 15; *see also* ComEd Ex. 20.0, p. 29) Staff maintains that the debt ratio under its proposed capital structure would be around 45% excluding the TFNs. That debt ratio is in the top third of the S&P ratio range for a BBB credit rating. (Tr., pp. 1845-1846) Staff further argues that even if the debt ratio was an appropriate consideration, the debt ratio under Staff's proposed capital structure supports at least a BBB+ credit rating when TFNs are excluded, if not higher.

Staff also provides testimony concerning the effect of excluding the TFIs for the FFOIC and FFO/Debt credit metric calculations. [FN15] Staff testified when the TFIs are excluded from the credit metric calculations, Staff's cost of capital recommendation would result in an FFO/ Debt and FFOIC ratios within the low to middle benchmark range for a BBB credit rating. Although the credit metric calculations without TFIs continue to reflect an adequate degree of financial strength, they do not produce ratios consistent with the A-/BBB+ credit ratings supported by the calculations including TFIs.

Staff argues that if the Commission concluded it were appropriate to impute a capital structure that would achieve credit metrics consistent with A-/BBB+ credit ratings (*i.e.*, consistent with the credit metrics achieved including TFIs), ComEd's equity ratio would need to be increased to approximately 45.5%. Table 2 presents the effect of a TFI Adjustment on the FFOIC and FFO/Debt ratios under Staff's cost of capital proposal. Table 2 also presents the common equity ratio, combined with Staff's proposed costs of common equity and debt, that would produce credit metrics similar to those that Staff's cost of capital proposal produces without the TFI Adjustment ('Target A-/ BBB+').

	Equity	A	BBB	BB			
Financial Guideline Ratios FFOIC		3.5-4.2X	2.5-3.5X	1.5-2.5X FFO/Debt	20-28%	12-20%	8-12%
Staff Proposal	37.11% FFOIC			3.06X FFO/Debt		13.91%	
Target A-/BBB+	45.5% FFOIC		3.69X FFO/Debt		18.19%		

****106** Staff argues that it does not support imputing a capital structure to achieve credit metrics excluding TFIs consistent with A-/BBB+ credit ratings since in Ms. Kight's opinion this would ultimately lead to a higher rate of return on rate base for ComEd. Staff's recommends a cost of capital of 7.86%. Combining a capital structure with a 45.5% common equity ratio and 54.5% debt ratio (to achieve credit metrics excluding TFIs consistent with A-/BBB+ credit ratings) with Staff's recommended costs of debt and common equity would result in a 8.17% cost of capital. Staff asserts that in Docket No. 98-0319, ComEd claimed that its proposed use ***262** of the proceeds from issuing TFNs would lower its cost of capital. [FN16] Consequently, Staff submits that it would be unfair to ratepayers to authorize ComEd a higher rate of return on rate base on the basis that the TFNs require ComEd to maintain a higher common equity ratio than had the TFNs not been issued.

Staff also offers testimony indicating that, under Ms. Kight's proposed capital structure, issuance of the TFNs does not increase the cost of capital in comparison to that which would have existed had no TFNs been issued. It is Staff's opinion that since the TFNs had a AAA credit rating at the time they were issued in December of 1998 and ComEd was rated BBB at that time, the interest rate on the TFNs is lower than that which ComEd would have paid had it issued conventional debt at that time. According to Ms. Kight on December 15, 1998, the 10-year corporate bond yield for electric companies with a credit rating of BBB was 6.32%. In Ms. Kight's opinion replacing the TFNs in the long-term debt schedule with conventional debt at a rate of 6.32% would increase the embedded cost of debt from 6.48% to 6.65%. Staff offers that when it uses the embedded cost of debt of 6.65%, its proposed capital structure, rate base and non-cash operating expenses result in a FFOIC ratio of 3.67X, a FFO/Debt ratio of 17.74%, [FN17] and an overall cost of capital of 7.96% - ten basis points higher than its recommended cost of capital.

In summary, Staff asserts that the imputed capital structure of 45.5% equity and 54.5% debt that is necessary to maintain TFI-adjusted financial benchmarks indicative of A-/BBB+ credit ratings increases the overall cost of capital from Staff's proposed 7.86% to 8.17%. Staff argues the Order in Docket No. 98-0319 found that ‘the record reasonably demonstrates that issuance of the Notes [(*i.e.*, TFNs)] and application of the proceeds as proposed by ComEd will result in a reduction in its overall cost of capital.‘ (Order, Docket 98-0319, July 21, 1998, p. 22) Staff contends that since the standard is and should remain that TFNs do not increase the cost of capital in comparison to that which would have existed had no TFNs been issued, the Commission should not impute a capital structure with a higher proportion of common equity on the basis of ratios calculated with the TFI Adjustment.

CUB-CCSAO-City

****107** CCC argues that ComEd's proposed capital structure is laden with far too much common equity. CCC states that because common equity is significantly more expensive than long-term debt, the excess common equity in ComEd's proposal substantially increases the utility's revenue requirements and, thus, costs for customers.*Seee.g.*, IIEC Ex. 3.0 at 17, L. 390-99.

CCC asserts that ComEd is the only party supporting its proposed capital structure. CCC claims the other parties submitting testimony on this issue agree that ComEd's appropriate capital structure should be 62.89% long-term debt and 37.11% common equity as proposed by Staff witness Sheena Kight and adopted by CCC witness Mr. Bodmer and IIEC witness Mr. Gorman. Staff Ex. 4.1; CCC Ex. 4.0 (Corrected) at 2, L. 50-57; IIEC Ex. 7.0 at 6, L. 124-31.

CCC argues that the primary difference between the unified recommendations submitted by Ms. Kight, Mr. Bodmer and Mr. Gorman and ComEd's go-it-alone approach is the treatment of the goodwill asset created at the time of the Unicom-PECO merger that led to the formation of Exelon, ComEd's parent corporation. CCC argues the Unicom-PECO merger created a $4.926 billion goodwill asset that is recorded on ComEd's balance sheet. IIEC Ex. 7.0 at 5, L. 105-06. CCC further argues because goodwill does not produce revenues or cash flows, it cannot be treated as debt.*Id.* at 8, L. 185-86. CCC contends that as a result, the goodwill on ComEd's balance sheet increases ComEd's equity balance. CCC Ex. 1.0 (Revised) at 23, L. 676-78.

According to CCC, while ComEd proposed to remove $2.292 billion of the goodwill asset from its balance sheet for purposes of determining the appropriate capital structure, the utility asserted that the remaining portion of the goodwill asset - some $2.634 billion - should remain as part of the utility's common equity balance. March 22, 2006 Tr. at 483-84 ***263** (HOUTSMA); MARCH 30, 2006 TR. AT 2473 (MITCHELl). ccc contEnds THAT THE $2.634 billion goodwill asset that ComEd claimed should be included in the utility's common equity balance is associated with its decision to transfer its nuclear plants to an affiliate - plants that ComEd no longer owns. IIEC Ex. 7.0 at 5, L. 113-18.

CCC states that Mr. Bodmer, Ms. Kight and Mr. Gorman agreed that the entire $4.926 billion goodwill asset should be excluded from ComEd's capital structure because the costs approved in this proceeding must be shown to support distribution and transmission assets needed to provide service to customers. CCC states each of these witnesses argued that the $2.634 billion goodwill asset that ComEd contended should be included in its common equity balance has nothing to do with providing delivery services to ratepayers.

CCC asserts that perhaps the most compelling evidence that demonstrated that ComEd's proposal to include a portion of its goodwill asset in its capital structure improperly inflated its common equity balance occurred during the cross-examination and re-direct examination of IIEC witness Mr. Gorman. CCC states that during cross-examination, Mr. Gorman testified that ComEd includes more than $11 billion in capital on its balance sheet. Yet, the utility has a little more than $6 billion in rate base. March 29, 2006 Tr. at 1986.

****108** So, clearly, there's a significant mismatch between the capital on the balance sheet and the amount of rate base. That difference in - from my perspective, that difference in the capital in rate base is largely attributable to almost a five billion dollar goodwill asset which is not the transmission and distribution utility asset. And that asset - that goodwill asset is completely supported by common equity.

So the amount of capital - ComEd's common equity in that 11 billion dollar capital component needs to be reduced by the value of that goodwill asset. That's supported only by common equity or roughly five billion dollars - or no, 4.96 billion dollars. So when you take ComEd's common equity and reduce it by 4.96 billion dollars of common equity and say that's supporting the goodwill asset and the remaining common equity is supporting transmission and distribution utility plant, then you get a capital structure that roughly matches rate base.

Id. at 1986-87.

CCC asserts that IIEC Redirect Ex. 1 effectively illustrates the explanation Mr. Gorman provided during his cross-examination. According to CCC, IIEC effectively demonstrates the mismatch between amount of capital ComEd shows on its balance sheet and the capital in rate base included in this case.

CCC claims that the record shows that ComEd is alone in its support of its proposed capital structure. In CCC's opinion all other witnesses testifying about this issue agreed that ComEd's proposed capital structure is laden with excess common equity. CCC avers that the primary source of the excess common equity is goodwill asset that has nothing to do with transmission and distribution assets that ComEd includes in its rate base. CCC argues the goodwill asset is wholly unrelated to the objective of this case - determining the costs needed to provide utility service. CCC further argues the goodwill asset merely inflates the common equity component of the utility's capital structure and, therefore, the rates that customers must pay. As a result, the CCC recommends that the Commission adopt the capital structure proposed by Staff witness Kight and adopted by CCC witness Bodmer and IIEC witness Gorman.*IIEC*

IIEC states ComEd has proposed a capital structure made up of 54.2% common equity and 45.8% debt to develop its overall cost of capital. IIEC witness Gorman opposed that capital structure as too heavily weighted with equity, which is more costly for ratepayers. Mr. Gorman argues that ComEd did not fully remove the common equity supporting goodwill from ***264** its proposed ratemaking capital structure. After considering the evidence, the testimony of other experts, and the arguments of all parties, in his rebuttal testimony Mr. Gorman found that Staff's proposed capital structure was the best proxy of ComEd's total capital supporting the utility's delivery services. He recommended adoption of Staff's capital structure - 37.11% equity and 62.89% debt. He stated that the structure is the result of including only equity that actually supports assets used in providing ComEd's delivery services. He opined that Staff's proposed capital structure should, therefore, be used to develop ComEd's overall rate of return for its delivery services.

****109** IIEC states both it and Staff pursued a common objective of developing a capital structure for ComEd that reflected the amount of common equity and debt that now support ComEd's transmission and distribution utility assets. IIEC further states that Staff and IIEC derived the common capital structure through distinct, independent (yet complementary) analyses.

In IIEC's opinion, the Commission should not give excessive weight to technical accounting mechanics to determine the equity component of the proper capital structure. IIEC says the Commission should not lose sight of the core issue: What is a reasonable capital structure that reflects the investment actually supporting ComEd's delivery services assets and operations?

IIEC believes that Mr. Gorman's approach to this question goes directly to the core issues. IIEC argues the Commission must determine a capital structure that is reasonable and that reflects the capital supporting its regulated delivery service assets and operations. IIEC states that in contrast, ComEd includes equity that is not dedicated to the provision of delivery services in its proposed capital structure, unreasonably inflating the utility's revenue requirement as a result.

IIEC argues ComEd's balance sheet has over $11 billion in total capital and its test year rate base is $6 billion. IIEC asserts that b that ComEd does not need $11 billion of capital to finance a $6 billion rate base. IIEC states that the major difference between ComEd's rate base and total capital is a goodwill asset of about $4.9 billion. IIEC asserts that the evidence in the record clearly shows that that $4.9 billion goodwill asset is financed entirely by common equity. Thus, IIEC argues good will is not a transmission distribution asset, it's financed solely with common equity. IIEC contends that it is appropriate to carve that common equity out of the capital structure and attribute it only to the goodwill asset. According to IIEC this leaves approximately 6 to $7 billion in capital to finance a $6 billion rate base. IIEC says this is typical of what one normally sees from ComEd's capital structure in reviewing the utilities' actual capital structure and rates. IIEC says that total capital and rate case don't always match, but they are generally pretty close. So, IIEC states that it is appropriate under these circumstances to remove the common equity supporting the goodwill asset.

IIEC supports Staff's argument that the effects of ComEd's goodwill asset should be removed from the capital structure. IIEC says ComEd's goodwill asset is not a transmission or distribution asset and, it is not used in providing ComEd's delivery services. IIEC states ComEd has excluded it from its proposed rate base in this case. According to IIEC the common equity recorded when that goodwill asset was created is not capital that supports the rate base and services under Commission regulation. IIEC argues ComEd's goodwill must be supported by equity, since ‘goodwill does not produce revenues and cash flows, and therefore could not be supported by debt capital.‘ According to IIEC, the equity supporting ComEd's goodwill should be excluded from the capital structure used to determine ComEd's delivery services revenue requirement.

****110** IIEC says that since the objective in this proceeding is to measure ComEd's cost of providing regulated utility service, it is appropriate to look at ComEd's total capital and identify what part of that capital represents its cost of funding utility plant investments. IIEC reasons the capital structure proposed by Staff witness Ms. Kight and supported by IIEC is the proper assessment of that capital supporting regulated ***265** utility rate base and therefore should be adopted.

Commission Analysis and Conclusion

[55-57] At issue is the appropriate capital structure *for ratemaking purposes.* The capital structure for ratemaking purposes is based on original cost rate base, and may differ from the capital structure reported for operations.

There are two proposals before the Commission. Both exclude short-term debt from the capital structure, and both set the balance of preferred equity at zero. ComEd asks that the Commission adopt a capital structure of 54.2% common equity ('equity') and 45.8% long-term debt ('debt'). Staff proposes a structure of 37.2% equity and 62.8% debt. CCC and IIEC support Staff's proposal. (The IIEC originally advocated a 50%/50% structure but subsequently withdrew that recommendation and supported Staff's proposal. The Commission therefore does not view the 50%/50% structure to be at issue.

The dispute centers on whether to include or exclude for ratemaking purposes a net $2.634 billion goodwill asset. ComEd includes this amount in equity within its proposed capital structure; Staff excludes it. 'Goodwill' is an intangible that represents the difference in value between the original cost of assets and the value received for their sale or transfer.

The net $2.634 billion amount reflects Staff's elimination of $4.791 billion in goodwill generated by the transfer of the nuclear power plants formerly owned by ComEd and funded by ratepayers through rate base. The plants are now owned by an unregulated affiliate, either directly by ComEd's parent Exelon or through another Exelon subsidiary. The net $2.634 billion amount also reflects Staff's adjustment to set certain costs related to the merger of Unicom and PECO (into Exelon) to reflect original cost. (ComEd had already excluded from its proposal $2.292 billion in goodwill related to the Unicom/PECO merger.)

Staff states that, as a result of the nuclear plant transfer, ComEd neither owns the plant assets nor received other assets in exchange. Accordingly, Staff contends that the transfer distorted the relationship between ComEd's actual capital structure and the capital supporting its depreciated original cost rate base. Staff contends that the generation assets had an original cost book value of approximately $6.7 billion, and were transferred from ComEd at a restated fair value cost basis of approximately $2 billion, with all of the resulting goodwill remaining on ComEd's books. As a result, ComEd's actual capital structure was not reduced commensurate with the original cost book value of the assets and liabilities transferred.

****111** CCC and IIEC both point out that the goodwill asset is not used in providing transmission and distribution service, and therefore is not a cost recoverable in the instant delivery services rate case. ComEd's balance sheet has over $11 billion in total capital. Its test year rate base is approximately $6 billion. The difference is attributable to the goodwill asset of approximately $4.9 billion in gross, financed by common equity. CCC and IIEC contend that, because the goodwill is not used in providing delivery services, it is appropriate to remove the common equity supporting goodwill from ComEd's capital structure. The resulting structure is consistent with that defined by Staff's accounting analysis.

ComEd counters that Staff's resulting capital structure does not reflect its actual capital structure, and that such a ratio will incorrectly signal investors about the financial strength of the Company. ComEd also contends that maintaining goodwill requires no cash, so all of its proposed capital structure supports its utility business.

Furthermore, ComEd argues that the transfer of its assets was lawfully executed, and that GAAP requires the transfer at book value. ComEd charges that Staff seeks a second review of the transactions completed pursuant to prior approval, and that such result is illegal.

Finally, ComEd witness Dr. Hadaway criticizes the Staff proposal because it contains much more debt than the respective capital structures of the companies in the sample group utilized to estimate the cost of common equity. ***266** In light of the plant transfers, the Commission does not view a difference in the proportion of debt to signal a problem per se

The starting point for the analysis, however, is Section 9-201 of the Act (220 ILCS 5/9-201). It requires that the rates set in this case be 'just and reasonable,' and further specifies that 'the burden of proof to establish the justness and reasonableness of the proposed rates …shall be upon the utility. ' (220 ILCS 5/9-201(c).)

In *Citizens Utility Board v. ICC* (the 'CUB' case), the Appellate Court stated that 'the Act requires the Commission to establish rates which are just and reasonable for both the investors and the consumers.' (*CUB v. ICC*, 276 Ill. App. 3d 730, 737 (1995); *see also id.* at 736 (*citing Bus. & Prof'l. People for the Pub. Interest v. ICC* (1991), 146 Ill. 2d 175, 208 ('The Commission is charged by the legislature with setting rates which are just and reasonable * * * to the ratepayers [and] to the utility and its stockholders. ') and *Ill. Bell Tel. Co. v. ICC* (1953), 414 Ill. 275, 287 ('The rate making process under the act, *i.e.*, the fixing of just and reasonable rates [,] involves a balancing of the investor and the consumer interests.')).) The Court also stated in the *CUB* case that '[c]urrent ratepayers should pay for only that plant which produces current benefits.' (276 Ill. App. 3d at 741.)

That case applied the just and reasonable requirement to the capital structure.*Citing* Section 9-230 of the Act, the Court stated:

****112** [t]he legislature has directed the Commission to protect against the increased cost of capital sought by a utility with such an inflated level of equity. * * * [T]he Commission should disallow recovery of any cost of capital in excess of that reasonably necessary for the provision of services. If a utility has included excessive equity in its capital structure, it has inflated the rate of return and its capital cost.

(*Id.* at 745-46.)

Section 9-230 provides that:

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

(220 ILCS 5/9-230.) A year later, the Court discussed the *CUB* and *Business and Professional People* cases, and held:

Before deciding whether to use a hypothetical capital structure, the Commission was required to determine whether either Bell's risk or cost of capital were increased because of its affiliation with Ameritech. …We hold that if a utility's exposure to risk is one iota greater, or it pays one dollar more for capital because of its affiliation with an unregulated or nonutility company, the Commission must take steps to ensure that such increases do not enter in its ROR [rate of return] calculation.

(*Ill. Bell Tel. Co. v. ICC*, 283 Ill. App. 3d 188, 206-207 (1996).)

Staff, CCC, and IIEC all argue that ComEd should not earn a rate of return on plant it does not own and does not use for providing distribution services. This view comports with the language of Section 9-230 of the Act, as discussed in the *CUB* and *Illinois Bell* cases. (*See supra*.)Furthermore, ComEd's equity figure contains the net $2.634 billion in goodwill generated from the transfer of its plants. Including this figure in equity necessarily will raise the required rate of return, and therefore the rates set herein.

The Commission finds that ComEd may not make such a recovery through regulated rates. Any recovery of the cost of plant owned by an unregulated generating affiliate will be recovered through the cost of power procured from such affiliate. The Commission therefore further finds that a recovery of such costs in rates by counting the goodwill in equity constitutes a double recovery, is not related to the regulated activities covered by these rates, and accordingly is neither just nor reasonable within ***267** the meaning of Section 9-201 of the Act.

ComEd's argument that it might have structured the transfer differently to effectuate the same at original cost is directly related to the issue of earning a return on plant it does not own. ComEd states:

ComEd pointed out that the proponents of the artificial 37/63 capital structure assume, without evidence that, had ComEd been required to transfer the assets at value (billions of dollars above book), it still would have structured the transfer in exactly the same way. Houtsma Sur., ComEd. Ex. 35.0, 18:386-89. ComEd explained that once the value of the plants is assumed to be different by billions of dollars, there is no basis in logic, fairness, business judgment, or common sense for assuming that the value is the only element of the transaction that would have changed. Mitchell Sur., ComEd Ex. 37.0 2nd Corr., 13:270-15:305. ComEd further noted that the artificial 37/63 capital structure becomes even less plausible when the resulting impact on equity is considered: *ComEd has consistently managed its capitalization to achieve an equity balance above $5 billion, yet the equity balance that would have resulted from a transfer where nothing but the value is changed would be inconsistent with that practice. ComEd explained that this is important, given that ComEd could have avoided the impact on equity by structuring the nuclear asset transfer differently*.

****113** (ComEd Position Statement/Draft Order (May 4, 2006) at 92 (emphasis added); *see also* ComEd Init. Br. at 167-169 (stating the same at greater length).)

The Commission notes that Section 16-111(g)(4) of the Act provides that '[d]uring the mandatory transition period, an electric utility may * * * record reductions to the original cost of its assets.' The Commission therefore views ComEd to admit in its initial brief (at 167-169) and in its position statement (at 92) that ComEd could have chosen to structure the transfer differently, but that it elected not to set the original cost of the transferred assets to their fair value under Section 16-111(g)(4) of the Act. Had it done so, the transaction would not have produced such an enormous difference between the original cost and fair value of the transferred plants, *i.e.* goodwill. Instead, by disregarding Section 16-111(g)(4), ComEd created a goodwill asset of $4.791 billion.

The Commission finds that this situation falls well within the 'increased cost of capital …which is the direct or indirect result of the public utility's affiliation with unregulated or nonutility companies' prohibited by Section 9-230 of the Act. It similarly reflects the 'inflated level of equity' discussed in *CUB v. ICC*, and the 'one dollar more for capital because of its affiliation with an unregulated or nonutility company' holding of *Ill. Bell v. ICC* (*see supra*.)In light of all this, the Commission rejects ComEd's proposed equity figure of 54.2%, which includes a recovery from rate payers based on billions of dollars of goodwill that was avoidable under Section 16-111(g)(4).

The foregoing determination is confined to the unjustness and unreasonableness of ComEd's proposal to recover a return on billions of dollars of plant it does not own through a mechanism that the Company admits it did not have to use. It also reflects the Commission's concurrence with Staff that the 'actual' capital structure proposed by ComEd in this case is distorted relative to original cost rate base. It does not constitute a review of, or change to, prior matters. Furthermore, it does not change the methodology of setting rates (for any utility) according to depreciated original cost rate base. Equally important, the equity at issue plainly does not support ComEd's provision of its regulated delivery services.

Although there are only two proposals and ComEd's has been rejected, the analysis is not yet complete. As noted above, Illinois Courts have repeatedly stated that the rates established herein must be just and reasonable for both ratepayers and investors. The Commission must determine whether Staff's proposal of 62.89% debt and 37.11% equity is, in fact, just and reasonable.

In light of the foregoing discussion, the Commission believes that Staff's adjustments ***268** have merit, and the Commission is satisfied that Staff's capital structure properly reflects ComEd's level of debt. While Staff contends that the proportions of equity in ComEd's last three rate cases were 38.97%, 39.40%, and 42.86% respectively, the Commission remains concerned that Staff's proposal may not be sufficient to allow the utility to maintain its financial strength or A-credit rating. Accordingly, the Commission declines to adopt a capital structure of 62.89% debt and 37.11% equity.

****114** The Commission observes that Illinois Courts have repeatedly stated that setting rates is a legislative function. (*See,e.g., Bus. & Prof'l People for Pub. Interest v. ICC*, 146 Ill. 2d 175, 196 (1991); *Ill. Cent. R.R. Co. v. ICC*, 387 Ill. 256, 275 (1944); *City of Chicago v. ICC*, 281 Ill. App. 3d 617, 622 (1996); *CUB v. ICC*, 276 Ill. App. 3d 730, 734 (1995).) The Commission therefore concludes that in determining whether a proposed capital structure is just and reasonable, it is the duty of the Commission to protect both ratepayers and investors.

Weighing all of the considerations discussed above, the Commission finds that it is appropriate to impute a capital structure of 42.86% equity and 57.14% debt. This capital structure is equivalent to what the Commission determined to be sufficient to maintain a reasonable level of financial strength in Docket No. 01-0423.The Company has been able to maintain an investment grade credit rating based on the previously determined capital structure. The Commission believes that such structure reflects Staff's adjustments to set rates based on original cost and trims ComEd's balloon of goodwill resulting from the plant transfers to unregulated affiliates.

2. COST OF LONG-TERM DEBT

ComEd

[58, 59] ComEd proposed a cost of long-term debt of 6.50%. ComEd states that this is its actual cost of such debt as of June 30, 2005, the historic capital structure measurement date used for ComEd's capital structure.

With respect to Staff's suggestion that ComEd's long-term debt cost be reduced to 6.48% (Kight Dir., Staff Ex. 4.0 Corr., 3:48-50), ComEd argues that the ending balances and amortization amounts behind that suggestion are not correct. ComEd offers that when the correct balances and amortization amounts are used - as shown in ComEd Exhibits 20.5a and 20.5b - ComEd's cost of long-term debt is 6.50%, just as ComEd is proposing. Mitchell Reb., ComEd Ex. 20.0 Corr., 28:602-29:609; ComEd Ex. 20.5a; ComEd Ex. 20.5b. ComEd also states that although Staff witness Sheena Kight claimed that she did not use ComEd Ex. 20.5b, the balances and amortization amounts reflected in that Exhibit are accurate and in accordance with applicable accounting and amortization principles. [FN18] Thus, ComEd states its actual balances and amounts - not Staff's modified ones - should be used in computing ComEd's cost of long-term debt. Mitchell Sur., ComEd Ex. 37.0 2nd Corr., 24:466-81.

ComEd asserts that CCC's claim that ComEd's long-term debt cost should be cut all the way down to 6.23% is even more untenable. ComEd offers several grounds on which it was inappropriate for CCC to suggest that a hypothetical cost based on Exelon Corporation's cost for debt issued in 2005 be substituted for the actual cost of actual ComEd debt maturing before or soon after ComEd's new rates go into effect in 2007. Bodmer Dir., CCC Ex. 1.0 2nd Corr., 33:982-85. ComEd argues such a hypothetical cost is based on another corporation's debt, not ComEd's. ComEd asserts that it included the actual cost of its own debt - that is, the debt that it actually is required to pay - when determining its weighted average cost of capital. ComEd contends, therefore, that the actual cost of debt, not some hypothetical one, is the appropriate test when determining ComEd's cost of capital. Mitchell Reb., ComEd Ex. 20.0, 26:559 27:565.

****115** ComEd says that Mr. Bodmer's hypothetical cost was flawed in several other respects as well. ComEd states that such cost included $300 million of short-term debt, even though such debt does not belong in the capital structure for the test period. Mitchell Reb., ComEd Ex. 20.0 Corr., 27:580-84; CCC Ex. 1.01, p. 2. ***269** ComEd also claims that Mr. Bodmer's hypothetical cost was based on debt issued in mid-2005, when interest rates were at an historically low level, from which they have since increased. ComEd also argues that Mr. Bodmer's proposed adjustment is inconsistent with the filing requirements in 83 Ill. Admin. Code Sections 285.4000 through 4030, as that proposal would incorrectly calculate ComEd's cost of debt as called for by such requirements. Mitchell Reb., ComEd Ex. 20.0 Corr., 28:591-601.

ComEd states that Mr. Bodmer's proposal was yet another example of CCC's ongoing effort to ignore ComEd's actual costs. In support of this position, ComEd claims that CCC does not question ComEd's use of June 30, 2005 for an historic measurement period date or its computation of its cost of long-term debt. Bodmer Dir., CCC Ex. 1.0 2nd Corr., 33:1004- 07. Nor, ComEd claims, did CCC suggest that such cost was imprudent or unreasonable. Instead, ComEd argues, CCC wants the Commission to ignore these facts, to go well beyond even the *pro forma* period, and to use a hypothetical cost from a holding company that reflects interest rates at their lowest point in recent history and that has nothing to do with the actual costs that ComEd will incur for debt between now and 2007.

Staff

Staff witness Ms. Kight testified that ComEd's embedded cost of long-term debt for June 30, 2005 equals 6.48%. (ICC Staff Exhibit 4.0 Corrected, pp. 3-4; Schedule 4.2, p. 3) To make this determination Ms. Kight stated she prepared a December 31, 2004, debt schedule (Schedule 4.2, pp. 4-6) making certain adjustments to the December 31, 2004 debt schedule presented on ComEd's Schedule D-3 Revised. First, she used the ending balances for unamortized losses presented in ComEd's 2004 Form 21 ILCC on pages 24a-24d for all issues redeemed before 1998. Second, she used straight line amortization of the Net (Gain) or Loss from the date reacquired to December 31, 2004 to determine the December 31, 2004 unamortized balance for the issues reacquired during 2004. Finally, Ms. Kight stated she adjusted the annual amortization of debt discount, premium, and expense to reflect straight-line amortization of each issue's December 31, 2004 unamortized balances over its remaining life. (*Id.*) Ms. Kight then stated she prepared a June 30, 2005 debt schedule (Schedule 4.2, pp. 1-3) by simply updating the 2004 debt schedule to reflect the additional annual amortization of debt discount, premium, and expense and the annual sinking fund redemption, the retirement of two issues, and the issuance of one new issue. (ICC Staff Exhibit 4.0 Corrected, p. 4)

Staff argues that ComEd's initial response to Ms. Kight's determination that ComEd's embedded cost of long-term debt for June 30, 2005 equals 6.48% was to simply contend that she failed to use the balances and amortization amounts provided by the Company in its data request response (attached as ComEd Exhibits 20.5a and 20.5b). (ComEd Ex. 20.0, pp. 28-29) Ms. Kight responded that she did use the balance presented in ComEd Exhibit 20.5a, but did not use the balances and amortization provided in ComEd Exhibit 20.5b because in her opinion some of those numbers did not reflect straight line amortization. (ICC Staff Exhibit 15.0 2nd Corrected, p. 5) Rather, the loss on reacquired debt presented in Ms. Kight's long-term debt schedule reflects the use of straight line amortization. (*Id.*) According to Staff, Ms. Kight began with the ending balances for unamortized loss and gain on reacquired debt presented on pages 24a and 24b of ComEd's 2004 Form 21 ILCC, and set the annual amortization of loss to that which would recover that loss in equal amounts each year (*i.e.*, straight-line amortization), consistent with the Commission's rule regarding the amortization of Unamortized Loss on Reacquired Debt. (*Id.*,*see* General Instruction 17 of the ‘Uniform System of Accounts for Electric Utilities ‘, 18 CFR 101 (2003), as adopted by 83 Ill. Adm. Code 415.10, subject to the exceptions set forth in 83 Ill. Adm. Code 415.380) Staff states that Ms. Kight calculated the ending balance for June 30, 2005 by subtracting 6months of amortization from the unamortized balance at December 31, 2004. ***270** Staff further explains that in addition, Ms. Kight made an adjustment (also provided in ComEd Ex. 20.5a) to reflect the generation-related unamortized loss on reacquired debt that was written off in December 1997. (ICC Staff Exhibit 15.0 2nd Corrected, p. 5)

****116** Ms. Kight further explained why and how she determined that the amounts contained in ComEd's Exhibit 20.5b failed to reflect straight-line amortization:

To illustrate, the unamortized balances of loss on reacquired debt for the 8.750%, Series 30 as of December 31, 2004, are the same on ICC Staff Exhibit 4.0, Schedule 4.2 and ComEd Ex. 20.5b. However, the June 30, 2005 unamortized balances differ. The annual amortization of Series 30 loss is approximately $90,900 using straight line amortization. Therefore, the June 30, 2005 balance should equal the December 31, 2004 balance of $772,849 minus half of the $90,900 annual amortization, or approximately $727,400. However, ComEd Ex. 20.5b lists the June 30, 2005 balance as $647,306. The approximately $80,000 difference between the two June 30, 2005 balances indicates that ComEd's balance does not reflect straight line amortization.

(*Id.*, p. 6)

Staff states that the surrebuttal testimony of ComEd witness Mr. Mitchell makes the conclusory assertion that he does not agree with Ms. Kight's position ‘because the balances and amortization amounts shown on ComEd Exhibit 20.5b are accurate and in accordance with applicable accounting and rate making principles.‘ (ComEd Ex. 37.0 2nd Corrected, p. 24) Staff argues that ComEd did not offer any analysis or explanation attempting to refute Ms. Kight's specific demonstration that ComEd's balances and amortization amounts do not reflect straight line amortization. Given that General Instruction 17 of the Uniform System of Accounts for Electric Utilities provides for the use of straight line amortization, Staff submits that Ms. Kight's recommended cost of long term debt is the only recommendation supported by the record that is consistent with Part 415.

CUB-CCSAO-City

CCC argues that ComEd's proposed long-term debt cost of 6.50% is overstated and should be reduced to 6.23%. CCC claims that ComEd's calculation of its long-term debt cost includes debt issues that will mature before the rates in this case will become effective (*i.e.*, January 1, 2007). CCC Ex. 1.0 (2nd Revised) at 33, L. 1005-08. CCC states that because these debts will mature at or near January 1, 2007, they will not affect the utility's interest expense once the new rates are in place.*Id.* at 34, L. 1012 15.

Rather than include the cost of debt that will mature at or near the time the new rates become effective, CCC claims that it is appropriate to assume that the maturing debt will be refinanced.*Id.* at L. 1019-21. CCC proposes that the cost of debt that Exelon issued to partly fund ComEd's pension obligations - costs the utility will incur when the new rates are in place - be used as a proxy for the cost of the maturing debt, *Id.* at L. 1025-26. CCC states that the cost of the Exelon-issued debt is fixed at 4.813%. CCC opines that the amount of the Exelon debt issue allocated to ComEd - $803 million - is approximately equal to the amount of debt that is maturing before or near January 1, 2007 - $807 million.*Id.* at 1027-31; CCC Ex. 1.01 at 2. CCC states that replacing the cost of the maturing debt with the cost of the Exelon-issued debt reduces ComEd's cost of long-term debt from 6.5% to 6.23%. CC Ex. 1.01 at 3.

****117** CCC argues that debt issues that will mature at or near the time rates go into effect are not relevant for ratemaking purposes. Therefore, CCC recommends that the Commission exclude these debt issues from the calculation of ComEd's cost of long-term debt. In their place, CCC proposes that the Commission adopt Mr. Bodmer's proposal to use the cost of the Exelon-issued debt as a proxy for the debt that will mature on or near January 1, 2007. CCC asserts that this provides a truer representation***271** of ComEd's debt cost when the rates established in this case are in place.

Commission Analysis and Conclusion

The Commission finds that ComEd's actual ending balances and amortization amounts of unamortized loss on reacquired debt as of June 30, 2005, do not reflect the use of straight line amortization and thus are inconsistent with the Commission rules regarding the amortization of Unamortized Loss on Reacquired Debt. (*See* General Instruction 17 of the ‘Uniform System of Accounts for Electric Utilities‘, 18 CFR 101 (2003), as adopted by 83 Ill. Adm. Code 415.10, subject to the exceptions set forth in 83 Ill. Adm. Code 415.380). The Commission further finds that Staff's are consistent with the Commission rules and reflect a cost of long-term debt of 6.48%, and thus rejects ComEd's proposed cost of debt of 6.50%, which is not based on straight-line amortization. The Commission also finds no merit in CCC's suggested hypothetical cost - the record shows, among other things, that such cost is based on a different corporation's debt, improperly includes $300 million of short-term debt, and is based on debt issued in mid-2005, when interest rates were at an historically low level. Indeed, CCC does not question ComEd's use of June 30, 2005 for an historic measurement period date or its computation of its cost of long-term debt, nor suggest that such cost was imprudent or unreasonable. Accordingly, the Commission concludes that ComEd's use of its actual long-term debt cost is appropriate

3. COST OF COMMON EQUITY

ComEd

[60] ComEd proposed a cost of common equity ('COE') of 11.00%. ComEd witness Dr. Hadaway states that this proposal was based on the widely accepted discounted cash flow ('DCF') and risk premium methods (including the capital asset pricing model ('CAPM')), which together provide the 'most reliable cost of equity estimate.' Hadaway Dir., ComEd Ex. 8.0, 1:15-21, 16:338-17:369, 23:495-503, 36:826-38:873.

Dr. Samuel Hadaway, who conducted these analyses for ComEd, testified that he used a comparable company approach, following the United States Supreme Court's traditional *Hope* and *Bluefield* requirements, [FN19] and drawing on companies tracked by *Value Line Investors Service* ('Value Line'), a 'widely-followed, reputable source of financial data.' Dr. Hadaway states that the comparable companies were comprised of regulated gas local distribution companies and electric utilities with risk profiles similar to ComEd's. ComEd argues that both of these groups are 'useful proxies' that the Commission has accepted for establishing COEs on several prior occasions. ComEd also says that Dr. Hadaway used multiple measures to ensure comparability, restricting his sample to companies that, among other things, have bond ratings of at least triple-B plus, have received at least 66% of their revenues from domestic utility sales, are currently paying dividends, with no dividend cuts in the last two years and have no current merger activities. Hadaway Dir., ComEd Ex. 8.0, 2:35-3:47, 5:106-11, 6:114-19.

****118** According to ComEd Dr. Hadaway used *Moody's* average public utility bond yields and projected single-A utility rates, and reviewed Value Line's projected earned rates of return for the comparable company groups in conducting his risk premium analysis. ComEd further states that Dr. Hadaway developed a CAPM estimate of the cost of equity for each group. ComEd also noted that under current market conditions, this combination of approaches was the most reliable method for estimating ComEd's COE. Hadaway Dir., ComEd Ex. 8.0, 3:48-58.

ComEd asserts that other parties' proposed COEs - 10.19% (Staff), 9.90% (IIEC), and 7.75% (CCC) - are deficient in multiple respects. Fundamentally, ComEd argues, each of these proposals is significantly below the COEs approved in recent years for electric utilities in the United States. ComEd states, for instance, that in the fourth quarter of 2005, the average COE allowed in eleven cases was 10.75%. Dr. Hadaway testifies that the COEs ***272** being proposed by other parties here constitute a 'departure for the trend of rising capital costs,' and are 'well below the mainstream' of COEs in the United States. Hadaway Reb., ComEd Ex. 21.0, 1:21-2:30; Hadaway Sur., ComEd Ex. 38.1. Dr. Hadaway further testifies that this conclusion is particularly apparent with respect to CCC's proposal, which is not only 300 basis points below the national average, but also 244 basis points below Staff's already low proposition, and still 215 basis points below IIEC's even lower suggestion. Hadaway Reb., ComEd Ex. 21.0, 17:381-93.

ComEd claims that in contrast, its own proposal of 11.00% is close to the national average. ComEd argues that this COE makes sense, that ComEd competes in the national equity markets and given the operating and capital risks that ComEd faces - such as continued dependence on kilowatt-hour volumes to recover costs, competition from self-generation and distributed generation, regulatory lag, potential disagreements over appropriate expenses and operating decisions, and responsibilities as the ultimate provider of last resort. ComEd asserts that these kinds of risks have been noted by rating agencies, and reflected, for instance, by ComEd's having a higher risk profile than most distribution utilities, as well as by the recent downgrading of the long-term rating on ComEd's senior unsecured debt. Hadaway Reb., ComEd Ex. 21.0, 2:41-45, 3:64-4:91.

ComEd argues that the contrast in proposed COEs is even more stark when ComEd's capital structure is considered. ComEd states that its proposed equity ratio of 54.2% is based on its actual historical capital structure as of June 30, 2005, and includes a voluntary adjustment to eliminate the $2.3 billion equity impact resulting from the required use of purchase accounting to reflect the Unicom/PECO merger. Mitchell Sur., ComEd Ex. 37.0 2nd Corr., 12:242-56. ComEd also states that this equity ratio lines up well with the equity ratios of the companies in Dr. Hadaway's comparables groups, which averaged 51.8% for the LDC group and 45.7% for the electric utilities. Hadaway Reb., ComEd Ex. 21.0, at 15:347-62. In contrast, ComEd argues, Staff, IIEC, and CCC, however, are pushing for a dramatically lower equity ratio of 37.11%, yet have failed to adjust for the additional financial risk entailed by such a highly leveraged capital structure. Kight Reb., Staff Ex. 15.0 2nd Corr., 8:127; Gorman Reb., IIEC Ex. 7.0, 11:236-45; Bodmer Reb., CCC Ex. 4.0 Corr., 2:50-51, 18:543-19:551; Hadaway Reb., ComEd Ex. 21.0, 6:131-7:144, Hadaway Sur., ComEd Ex. 38.0, 7:162-8:165. ComEd argues further that, as a result, these other parties' proposed COEs are mismatched with the comparable company groups proposed by Staff and IIEC, each of which involved companies with less leveraged capital structures. Hadaway Sur., ComEd Ex. 38.0, 2:30-33. As an example, ComEd pointed to Mr. McNally's electric group, which has an average COE in 2004 of 48.8% and a projected equity ratio for 2008-2010 of 52%. Hadaway Reb., ComEd Ex. 21.0, 6:131-7:144.

****119** ComEd further alleges that CCC's proposed COE is even more skewed. ComEd asserts that the proposal is not only more than one hundred basis points below any COE recently approved in the United States, but not even based on any of the theoretically correct estimation techniques customarily used by economists to estimate COE. Rather, according to ComEd, the proposal was generated primarily from inapplicable information published by three investment banks in valuing the proposed merger between Exelon and PSEG. Hadaway Reb., ComEd Ex. 21.0, 18:406-19:424.

GDP Growth Rate

ComEd alleges that in preparing his DCF analysis, Dr. Hadaway used GDP growth rates to gauge long-term growth expectations. ComEd noted that the DCF model calls for very long-term growth rates and such expectations are more closely predicted by broader measures of economic growth - like GDP - than by near-term analysts' estimates. Hadaway Sur., ComEd Ex. 38.0, 17:397-18:405. ComEd asserts by using GDP data Dr. Hadaway could look beyond the present low-inflation environment that has driven near-term growth estimates far below where they were just five years ago. ***273** Hadaway Reb., ComEd Ex. 21.0, 8:170-77.

ComEd alleges that Staff's and IIEC's proposed COEs are flawed because their DCF models fail to consider very long-term growth expectations. ComEd states that Mr. McNally used growth rates projecting earnings for only the next five years, and Mr. Gorman used growth rate estimates of only three to five years. Hadaway Reb., ComEd Ex. 21.0, 7:149-8:177, 11:240-47; Hadaway Sur., ComEd Ex. 38.0, 5:97-103. According to ComEd these shorter-run growth rates reflect today's historically low rates of inflation and analysts' less than optimistic outlook for the electric utility industry, which together skew DCF estimates abnormally low. Hadaway Sur., ComEd Ex. 38.0, 10:216-24.

Investment Bank Analysis

ComEd argues that CCC's use of the investment bank valuation analyses amounted to an improper mixture of ‘apples and oranges.‘ According to ComEd, the two efforts - calculating a discount rate for use in a fairness opinion and determining the cost of equity that the market requires that a utility earn for ratemaking purposes - are very different in purpose and methodology. For instance, ComEd states, a fairness opinion in a context like the proposed Exelon-PSEG merger is intended to provide a relative valuation of the two companies' stock at a certain point in time. ComEd also alleges that, in doing this kind of study, investment banks use various methodologies, which may or may not be similar to those appropriately used in a regulatory proceeding like this rate case. On the other hand, ComEd says, in such a regulatory proceeding, the purpose of estimating a utility's cost of capital is to allow the utility a reasonable return on its rate base. ComEd argues further that such a return includes a return on equity that is set by the market, rather than under Mr. Bodmer's implicit assumption that utility stocks should trade at book (discussed in the next subsection). Hadaway Reb., ComEd Ex. 21.0, 21:426-32; Hadaway Sur., ComEd Ex. 38.0, 14:311-22. For these reasons and others, ComEd argues, neither the Commission, nor any other utility regulatory in the U.S., has accepted Mr. Bodmer's methodology or approach.

****120** For example, ComEd states that Lehman Brothers (one of Exelon's investment banks) used internal forecasts and analyses of Exelon's financial performance and capital expenditures, rather than, for example, a typical regulatory DCF analysis based on data known to the public and revealed in stock prices. ComEd also says that Lehman Brothers conducted its analysis as of a specific point in time in the past, as opposed to determining a required rate of return for the future. Hadaway Sur., ComEd Ex. 38.0, 14:323-30.

In addition, ComEd alleges that while cost of capital in a regulatory proceeding is estimated for application to a utility's rate base - *i.e.*, its historical, depreciated investment - an investment bank may derive implied returns based on market-based valuations of those same assets, including the additional cost the utility would need to assemble the same mix of investments from scratch at current market prices. As such, ComEd argues, it would be inappropriate to apply the latter type of rate of return, which is based on a market-priced basket of assets, to a rate base defined by original cost. Hadaway Sur., ComEd Ex. 38.0, 15:331-38.

According to ComEd there are other differences, as well. For example, ComEd says, valuation analysis uses market-based capital structure weights, while regulatory analysis uses book weights. ComEd also says that valuation analysis relies on an estimate of the incremental, after-tax cost of debt, while regulatory analysis calls for the known and measurable embedded, pre-tax cost of debt. Hadaway Reb., ComEd Ex. 21.0, 19:432-36.

Market to Book Ratio

ComEd argues that Mr. Bodmer erred in suggesting that utility stocks should trade at book. ComEd states that when confronted with the fact that utility market-to-book ratios are greater than one for a number of reasons other than over earning, Mr. Bodmer claimed that 'regulatory commissions have been granting ***274** returns in excess of the cost of capital to utility companies. ' Bodmer Dir., CCC Ex. 1.0 2nd Corr., 45:1368-70. Thus, ComEd alleges, instead of recognizing that such ratios highlighted the unreasonableness of his own proposed COE, Mr. Bodmer implied that regulatory commissions around the country have been consistently wrong. ComEd concluded that such a stance just underscores how far out of the mainstream Mr. Bodmer is. Hadaway Reb., ComEd Ex. 21.0, 8:398-404.

Staff

According to Staff, Staff witness Mr. McNally estimated ComEd's investor-required rate of return on common equity to be 10.19%. (ICC Staff Exhibit 5.0, p. 18) In order to derive that estimation, Staff states that Mr. McNally measured the investor-required rate of return on common equity with discounted cash flow ('DCF') and Capital Asset Pricing Model ('CAPM') analyses. Mr. McNally applied those models to a sample of utility companies ('Comparable Sample') chosen on the basis of the comparability of their financial and operating ratios to those of ComEd. Staff states that Mr. McNally's sample selection analysis employed six financial and operating ratios, using the average from the period 2002-2004 to normalize the ratios. He conducted a principal components analysis of those financial and operating ratios for the 112 market-traded electric, natural gas, and water companies on *Standard & Poor's Utility Compustat* tape that had sufficient data to calculate the ratios. After calculating the scores for each principal component, he rank-ordered the companies in terms of least relative distance from ComEd's target scores. The Comparable Sample consists of the eight utilities which are the least distance from, and therefore, the most comparable to, ComEd that are assigned an S&P business profile score of three to five; have growth rates from Zacks Investment Research, Inc. ('Zacks'); and have neither pending nor recently completed significant mergers, acquisitions, or divestitures. (ICC Staff Exhibit 5.0, pp. 2-4)

****121** Mr. McNally testified that the DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments. Mr. McNally further testified that since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that stock prices embody. The companies in Mr. McNally's Comparable Sample pay dividends quarterly. Therefore, Mr. McNally applied a constant-growth quarterly DCF model. (ICC Staff Exhibit 5.0, p. 5)

Mr. McNally testified that the DCF methodology requires a growth rate that reflects the expectations of investors. Mr. McNally measured the market-consensus expected growth rates with projections published by Zacks. The growth rate estimates were combined with the closing stock prices and dividend data as of November 17, 2005. Based on this growth, stock price, and dividend data, Mr. McNally's DCF estimate of the cost of common equity was 9.36% for the Comparable Sample. (ICC Staff Exhibit 5.0, p. 8)

Mr. McNally's testimony also pointed out that according to financial theory, the required rate of return for a given security equals the risk-free rate of return plus a risk premium associated with that security. The risk premium methodology is consistent with the theory that investors are risk-averse and that, in equilibrium, two securities with equal quantities of risk have equal required rates of return. Mr. McNally used a one-factor risk premium model, the Capital Asset Pricing Model (‘CAPM‘), to estimate the cost of common equity. In the CAPM, the risk factor is market risk, which cannot be eliminated through portfolio diversification. (ICC Staff Exhibit 5.0, pp. 8-9)

Mr. McNally further testified that the CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. For the beta parameter, Mr. McNally says that he combined betas from Value Line and a regression analysis. The average Value Line beta estimate was 0.81, while the regression beta estimate was 0.62. (ICC Staff Exhibit 5.0, p. 16) Mr. McNally says that for the risk-free rate parameter, he considered the 4.06% yield on four-week U.S. Treasury***275** bills and the 4.81% yield on twenty-year U.S. Treasury bonds - Both estimates were measured as of November 17, 2005. Forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 5.4% and 5.9%. Thus, Mr. McNally concluded that the U.S. T-bond yield is currently the superior proxy for the long-term risk-free rate. (ICC Staff Exhibit 5.0, pp. 10-13) Finally, for the expected rate of return on the market parameter, Mr. McNally conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market equals 13.42%. (ICC Staff Exhibit 5.0, p. 14) Inputting those three parameters into the CAPM, Mr. McNally calculated a cost of common equity estimate of 11.01% for the Comparable Sample. (ICC Staff Exhibit 5.0, p. 17)

****122** Based on his DCF and risk premium models, Mr. McNally estimated that the cost of common equity for the Comparable Sample is 10.19%. To determine the suitability of that cost of equity estimate for ComEd, Mr. McNally assessed the risk level of his Comparable Sample relative to that of ComEd. To begin with, the companies composing the Comparable Sample were selected based on the similarity of their financial and operating ratios to those of ComEd. Further, the similarity in risk of the resulting Comparable Sample to ComEd is confirmed by the similarity in the sample average credit rating, business profile score, and factor scores to those of ComEd. Thus, Mr. McNally concluded that the Comparable Sample appropriately reflects the risk level of ComEd and no risk adjustment is necessary. (ICC Staff Exhibit 5.0, pp. 17-18)

GDP Growth Rate

Mr. McNally testified that the difference between Staff's and ComEd's cost of equity estimates is due almost entirely to Dr. Hadaway's inappropriate use of an economy-wide GDP growth rate as a proxy for the growth of the individual companies in his samples, which leads to an overstated cost of equity estimate. (ICC Staff Exhibit. 5.0, pp. 23-24) The Company failed to demonstrate that Dr. Hadaway's GDP growth rate estimate is a reasonable proxy for the growth of his individual sample companies. (ICC Staff Exhibit 16.0, p. 7) To the contrary, the record evidence indicates that Dr. Hadaway's approach is not appropriate.

First, Mr. McNally testified that the considerable divergence of Dr. Hadaway's 6.60% economy-wide GDP growth rate estimate from the three distinct company-specific growth rate estimates Dr. Hadaway employed suggests that his historical GDP growth rate is not a reasonable estimate of the sustainable growth of the individual companies in his samples. The sample averages for each of the three company-specific growth rate estimates for the companies in both of Dr. Hadaway's samples were quite consistent, all falling within a range of approximately one percentage point, from 3.41% to 4.43%. In contrast, the 6.60% GDP growth rate is more than two percentage points *higher* than the highest of any of the other three estimate averages for either sample. (ICC Staff Exhibit 5.0, p. 20)

Second, Mr. McNally testified that the Value Line earnings retention rate forecasts for the companies in Dr. Hadaway's samples, upon which Dr. Hadaway relied to develop his B*R growth rates, also indicate that 6.60% is not a reasonable estimate of the sustainable growth of the individual companies in his samples. As the B*R growth rate model indicates, a company's expected sustainable future growth is a product of the expected rate of return on new investment, R, and the percentage of earnings expected to be reinvested in the company (*i.e.*, the retention rate), B. The greater the rate of return on new investment and the earnings retention rate, the greater the growth rate. Conversely, the lower the rate of return on new investment and the earnings retention rate, the lower the growth rate. Given the Value Line retention rate forecasts, the return on retained earnings for the companies in his samples would have to average over 20%, which is almost twice the 11.0% cost of equity Dr. Hadaway estimated for those companies, in order to sustain 6.60% growth.[FN20] Conversely, given Dr. Hadaway's 11.0% final cost of equity estimate, ***276** the retention rate for those companies would have to average 60%, which is almost twice the average of the Value Line retention rate forecasts, which Dr. Hadaway relied upon for his analysis, in order to sustain 6.60% growth. Thus, a 6.60% growth expectation is both inconsistent with the rest of Dr. Hadaway's analysis and unlikely to be embraced by investors. (ICC Staff Exhibit 5.0, pp. 20-21) Mr. McNally further pointed out in his testimony that alternatively, if one assumes, for internal consistency, that both Dr. Hadaway's 11.0% final cost of equity recommendation and the Value Line retention rate forecasts Dr. Hadaway relied on are fairly reasonable estimates, then the sustainable growth rate for the companies in his LDC Sample and Electric Sample would average approximately 3.5% and 3.74%, respectively. Those estimates fall squarely within the 3.41% to 4.43% range of the sample averages for the three company-specific growth rates Dr. Hadaway employed and, thus, are clearly much more comparable to the company-specific growth rates Dr. Hadaway employed than to Dr. Hadaway's GDP growth rate estimate of 6.60%. (ICC Staff Exhibit 5.0, p. 23)

****123** In his testimony Mr. McNally testified that the Company's argument for the use of an economy-wide GDP growth rate as a proxy for the growth of the individual utility companies in Dr. Hadaway's samples rests on the implicit assumption that investors expect the long-term growth rates for those utilities to be similar to Dr. Hadaway's estimate of the average long-term growth rate for the overall economy. However, Mr. McNally asserts that ComEd has provided no information to demonstrate that the companies in Dr. Hadaway's samples are average growth companies. To the contrary, the data underlying Dr. Hadaway's own analysis suggests that the utility companies composing his samples are below average growth companies. Specifically, the retention rate for utility companies is typically well below average, as evidenced by the historical, current, and Value Line forecasts of the retention rates of the companies in Dr. Hadaway's samples relative to the average retention rate for the companies composing the S&P 500. Mr. McNally testified that one would expect utilities overall to earn below average returns due to the below average risk reflected in their below average betas (*i.e.*, betas less than one), such as the 0.81 and 0.74 average betas Dr. Hadaway adopted for his LDC Sample and Electric Sample, respectively. Since growth is a function of those below average earnings retention rates and the below average return on those retained earnings, one would clearly expect *below average* growth for utilities. (ICC Staff Exhibit 5.0, pp. 21-22) In its initial brief, Staff explains that the Company's entire argument rests on the hope that the Commission will completely disregard the consistent, established patterns from the available data and simply accept the unfounded suggestion that investors expect the long-term future for utilities, relative to the overall market, to be significantly different from both the past and present as well as from current projections of the future three to five years hence.

Staff also argues in its initial brief that even if one accepts the use of a GDP estimate as a proxy for the growth of the individual companies in Dr. Hadaway's samples despite the above arguments, the accuracy of Dr. Hadaway's long-term GDP growth rate estimate as a gauge of long-term GDP growth expectations is highly questionable. Staff asserts the Company failed to demonstrate that investors set their long-term expectations of future GDP growth based on growth achieved over that past 57 years, much less that they derive their expectations in the peculiar manner Dr. Hadaway did. Furthermore, Staff argues the actual, published GDP forecasts Staff and IIEC cited indicate that expectations for future GDP growth are significantly lower than the GDP growth rate Dr. Hadaway employed. (ICC Staff Exhibit 16.0, p. 8; IIEC Exhibit 3.0, pp. 3, and 25-26) Thus, Staff opines it is highly dubious to assume that investors expect 6.60% long-term growth for the overall economy, as measured by GDP, much less for utilities specifically.

****124** Finally, Staff in its initial brief argues that even if one ignores all of the foregoing arguments, the companies in Dr. Hadaway's samples cannot sustain a 6.60% growth rate given their current and forecasted dividend policies, even if ***277** one accepts the Company's supposition that investors might expect a return as high as 12.55%. Staff further argued that even in the unlikely event that investors do expect very long-run growth rates to be approximately 6.60%, they must also expect a significant change to those companies' dividend payout policies, all else equal. Staff states that change must be reflected in the DCF model, if one wishes to obtain an unbiased cost of equity estimate; unfortunately, the Company's analysis does not incorporate the necessary shift in dividend payment policies. Thus, Staff asserts, not only does the Company rely on the unfounded assumption that investors expect a dramatic rise in retention rates, but its analysis also implies that that rise in retention rates has already occurred, since it does not model any transition from the current retention rates to the higher retention rates that would be needed over the long run. In Staff's opinion the Company effectively overstates ComEd's cost of equity by combining the higher dividend yield resulting from the lower actual current retention rate with the higher growth rate associated with a higher assumed future retention rate. (ICC Staff Exhibit 16.0, pp. 1011) For all of the foregoing reasons, Staff argues that Dr. Hadaway's application of his GDP growth rate estimate as a proxy for the growth of the individual companies in his samples is inappropriate and should be rejected.

Investment Bank Analysis

Mr. McNally testified that uncertainties regarding the CCC analysis rendered the resulting cost of equity estimate inappropriate for rate setting purposes. Mr. McNally states that CCC estimated ComEd's cost of equity by inference from the weighted average cost of capital (‘WACC‘) calculated by Morgan Stanley for the merger of Exelon and PS&G. However, according to Mr. McNally, in order to back out the cost of equity from the investment bankers' WACC estimates, CCC first had to make numerous assumptions. Mr. McNally further testified that unfortunately, we do not know if Mr. Bodmer's assumptions were the same as those the investment bankers used. Thus, we do not know if the CCC cost of equity estimate is the same as that calculated by the investment bankers. For example, we do not know if the investment bankers used the same approach to determining the cost of debt, what mix of debt maturities they used, or if they included short-term debt. Further, Mr. McNally stated that it is unclear whether the Morgan Stanley analysis was for ComEd and PECO separately or for the proposed combined entity. Mr. McNally went on to state that we also do not know if the investment bankers used the same capital structure or made the same assumptions regarding the treatment of transitional funding instruments. Because of all of these unknowns, the Commission cannot be certain that the investment bankers used the same 7.75% cost of equity Mr. Bodmer inferred or, even if they did, that that estimate represents the required rate of return on equity appropriate for rate setting purposes. (ICC Staff Exhibit 16.0, pp. 15-16)

Market to Book Ratio

****125** Staff witness Mr. McNally testified that the CCC market to book value analysis is not useful for establishing ComEd's cost of common equity for several reasons. First, according to Mr. McNally, market to book value ratios combine the discounted value of future cash flows with historical book earnings. The numerator and denominator of the ratio are inconsistent with respect to time and construction. Second, Dr. Bodmer's market to book value analysis is based on the premise that one should expect a utility company to *precisely* earn its cost of capital on a continuing basis. That premise is oversimplified. Mr. McNally says there are many utility ratemaking practices (*e.g.*, deferred taxes and depreciation) that could result in a utility's market value exceeding its book value. That is, the authorized return for each company in Mr. Bodmer's sample is not the only factor influencing its earnings. Thus, a market to book ratio in excess of one does not necessarily mean the authorized rate of return is too high. Third, Mr. McNally says, the Value Line betas for the 71 companies used in Mr. Bodmer's analysis range ***278** from 0.50 to 1.75, indicating substantial variation in the riskiness of those companies. Yet, Mr. Bodmer's analysis suggests that there is a single correct cost of equity (*i.e.*, 5.65%), that which would equate market value to book value, for all 71 companies in his analysis. In addition, according to Mr. McNally, even if Mr. Bodmer were correct that the market to book value ratio for a utility that earned its required rate of return on common equity would equal one, companies with different risks must have different required rates of return. Thus, Mr. Bodmer's cross-sectional analysis is useless for establishing ComEd's cost of common equity given that he failed to establish that ComEd's risk is equal to the average risk of the 71 companies used in his analysis. (ICC Staff Exhibit 16.0, pp. 21-22)

CUB-CCSAO-City

CCC argues that because the cost of common equity is not a directly observable number, regulatory commissions have had to rely on subjective models, such as the capital asset pricing model (‘CAPM‘) and the discounted cash flow model (‘DCF‘), to estimate a utility's cost of common equity. According to CCC witness Bodmer, cost of capital discussions are often opaque and include such esoteric topics as ‘adjustments to beta for mean reversion, quarterly versus annual discounting in the DCF model, complex statistical research on the equity risk premiums, questions about inflation risk in long-term bonds and so on.‘ CCC Ex. 4.0 at 5, L. 128-31. CCC avers that this often difficult and confusing process has led to returns that are higher than the utilities' actual cost of capital.*See* CCC Ex. 1.0 (2nd Revised) at 40-45, L. 1205-1370.

CCC asserts that this case represents a unique opportunity for the Commission in that there is direct, observable data from less biased sources that the Commission can use to determine the appropriate cost of common equity for ComEd. In particular, CCC witness Bodmer developed his recommended cost of common equity based on his review of valuations conducted by three leading investment banks - Morgan Stanley, JP Morgan and Lehman Brothers - for the merger between Exelon and PSE&G. CCC argues that the valuations done by the three investment banks are a far more reliable indicator of investor needs than the subjective models that are used to bridge evidentiary gaps ‘that arise because the level of return required to induce real investors to provide capital for the firm is not directly observable.‘ CCC Ex. 1.0 (2nd Revised) at 5, L. 145-46. Mr. Bodmer explains that the coincidence of the Exelon-PSE&G merger provides evidence of the rate of return required by investors from three major investment banks on whom such real world transactions depend. Mr. Bodmer testifies that in the published documents relating to the merger we have more direct expressions of investor expectations than is usually the case. He states that the return on equity component used by investment banks in valuing free cash flows is the incremental return required by equity investors, exactly the same thing that [ComEd witness] Dr. Hadaway is estimating in his analysis. Mr. Bodmer further testifies that given the availability of such practical information, the Commission should not prefer the indirect and theoretical over the more direct, actual data available for its consideration. *Id.* at 6, L. 151-59.

****126** CCC asserts that this information is especially valuable because while investment banks and regulatory commissions use different methods to measure the cost of debt and to determine capital structures, ‘the cost of equity capital in the weighted average cost of capital is the same under the regulatory definition as it is for valuation analyses.‘ *Id.* at 10, L. 305-08. CCC argues in determining ComEd's cost of common equity, the investment banks and the Commission share a common goal - to establish ‘the opportunity cost that measures required returns for investments of similar risk.‘ *Id.* at 17, L. 503-05. CCC states that while ComEd witness Dr. Hadaway criticized Mr. Bodmer's use of investment bank valuations for determining his recommended cost of common equity, on cross-examination, Dr. Hadaway agreed that the cost of equity ***279** for valuation purposes has the same theoretical purpose as the cost of equity for regulatory purposes. March 30, 2006 Tr. at 2415.

CCC contends that because investment bank valuations are a direct proxy for investment requirements and are, therefore, inherently more objective than subjective applications of theoretical cost of equity models, Mr. Bodmer used the publicly available information regarding estimates of the weighted cost of capital developed by Morgan Stanley, Lehman Brothers and JP Morgan as part of the ongoing Exelon-PSE&G merger to establish his recommended cost of equity. Because Morgan Stanley developed a weighted cost of capital for ComEd, Mr. Bodmer based his cost of common equity analysis on Morgan Stanley's results.

According to Mr. Bodmer Morgan Stanley estimated a cost of capital for ComEd of between 5.25 and 5.75%. CCC Ex. 1.0 (2nd Revised) at 36, L. 1071-72. CCC explains that Mr. Bodmer inferred the cost of capital used by Morgan Stanley by making certain assumptions about ranges of ComEd's debt to capital ratio and incremental debt costs.*Id.* at 38, L. 1153-58. Mr. Bodmer's analysis showed that the range of the cost of common equity for ComEd is between 6.20% and 8.11%.*Id.* at 38-39, L. 1160-74. Based on his best estimate of ComEd's debt to capital ratio and incremental debt costs, Mr. Bodmer concluded that the utility's cost of common equity for this case should be set at 7.75%.

CCC argues that in his rebuttal testimony, ComEd witness Hadaway criticized Mr. Bodmer's use of the investment banks' valuations, claiming that ‘Mr. Bodmer's approach is fraught with personal judgment and considerable subjectivity.‘ ComEd Ex. 21.0 at 19, L. 437-38. To back up his assertion, Dr. Hadaway modified two assumptions used by Mr. Bodmer to derive a return on equity of 11.45%.*Id.* at 20, L. 444-45. Dr. Hadaway concluded that his exercise demonstrates the sensitivity of Mr. Bodmer's approach.*Id.* at 20, L. 454-46.

CCC argues that perhaps unwittingly, ComEd undercut its own expert. Attached to Dr. Hadaway's surrebuttal testimony was a letter that Lehman Brothers provided at ComEd's request. Although the letter was stricken from Dr. Hadaway's testimony (*see* ALJ Notice of Ruling, March 21, 2006), ComEd used the letter as a cross exhibit during its cross-examination of Mr. Bodmer.*See* March 24, 2006 Tr. at 1277-78; ComEd Cross Ex. 6. CCC points out that Mr. Bodmer testified that the most interesting part of the Lehman Brothers letter was the author's assertion that returns on equity ‘are typically 300 or more basis points more than the discount rates used in investment bank fairness opinions.‘ ComEd Cross Ex. 6 at 3. CCC states that if one subtracts 300 basis points from Dr. Hadaway's recommended 11.0% cost of common equity, the result is 8.00% - a mere 26 basis points more than Mr. Bodmer's proposed 7.74% return on equity. March 24, 2006 Tr. at 1284. Thus, according to CCC, ComEd's cross exhibit confirms the reasonableness of Mr. Bodmer's assumptions in deriving his recommended return on common equity from Morgan Stanley's weighted cost of capital. CCC also states that Mr. Bodmer supported his conclusion regarding the cost of equity used by Morgan Stanley by applying more traditional cost of equity models. According to CCC, Mr. Bodmer conducted a CAPM analysis, a DCF analysis and a price to earnings ratio analysis. Mr. Bodmer's CAPM analysis yielded a range for cost of common equity of 6.69 to 7.31%. CCC Ex. 1.0 at 47, L. 1411-12. Mr. Bodmer's DCF analysis yielded a cost of common equity of 7.88%.*Id.* at 68, L. 2058. His price-to-earnings analysis yielded a cost of common equity of 7.84%.*Id.* at 68, L. 2060. CCC claims that each of these results confirm that Mr. Bodmer's investment bank analysis produces a reasonable cost of equity.

****127** CCC asserts that numerous changes that have occurred since ComEd's last DST case that support adoption of Mr. Bodmer's proposed 7.75% return on common equity. CCC claimed that, at a minimum, these factors show that if the Commission does not adopt Mr. Bodmer's proposal, it should adopt a return on common equity at the low range of the estimates provided by the other cost of capital witnesses. Among these factors are:

Changes in Personal Tax Rates - Since ***280** ComEd's last DST case, personal income tax rates on dividends and capital gains have been reduced. The effect of these tax changes mean that after-tax returns have increased by a substantial amount for a given level of pre-tax return. CCC Ex. 1.0 (2nd Revised) at 11, L. 323-25; at 13-14, L. 373-97.

Declines in Overall Level of Interest Rates - Overall interest rates have dropped since ComEd's DST rate case. At the time the order was entered in ComEd's last rate case, the yield on 10-year Treasury Bonds was 5.42%. When ComEd filed its current DST case, the long-term treasury rate was 4.02%. CCC pointed out that ‘the difference in interest rates of 1.40% is almost twice the difference in the allowed equity return from the last case versus [the utility's] request in this case (11.75% versus 11.0%.).‘*Id.* at 11, L. 326; at 14, L. 410-05.

Lower Business Risk for ComEd - In January of this year, the Commission approved ComEd's proposal to procure power post-2006 through an auction. The auction will allow the utility to pass generation costs directly to customers.*Id.* at 15, L. 425-26. IIEC witness Robert R. Stephens testified that this process allows ComEd to transfer ‘all fuel cost, power procurement costs, and other operating risk associated with generation supply from itself to customers and to wholesale generation suppliers in the market.‘ IIEC Ex. 1.0 at 4-5, L. 90-102.

Lower Revenue Volatility for ComEd - As part of its rate design, ComEd proposed to increase customer charges for residential customers. If accepted, the customer charge for single family customers would increase from $7.13 per month to $9.65 per month and for multi-family customers from $2.94 per month to $9.65 per month. CCC Ex. 1.0 at 15, L. 437-40. The effect of this proposal is to increase customers' fixed charge, which has the necessary consequence of reducing the volume risk that ComEd would face. In other words, ‘a greater proportion of ComEd's revenues will not be subject to any variation at all in energy usage‘ which reduces risk for the utility.*Id.* at 15, L. 440-41.

Completion of large investments in distribution plant - Following a number of well-publicized and widespread outages that occurred in 1999, ComEd undertook major capital investments in its infrastructure. CCC noted that according to ComEd witness John T. Costello, ComEd's requested rate base in this case is $2,572.5 million more than the level the Commission approved in ComEd's last rate case in 2001. ComEd Ex. 3.0 at 7, L. 138-40. CCC calculated that the proposed $2,572.5 million increase in rate base represents more than almost 42% of ComEd's proposed $6,189.2 million rate base in this case. CCC stated that this flurry of capital investments should ‘mean that rate base growth relative to sales growth should moderate, and potentially allow the [utility] to earn more than its allowed return.‘ CCC Ex. (2nd Revised) 1.0 at 11, L. 331-33. CCC noted that Mr. Bodmer's comment is supported by ComEd witness J. Barry Mitchell's statement that ‘we expect to finance the majority of ComEd's capital expenditures with internally generated cash… .‘ ComEd Ex. 7.0 at 5, L. 97-98. According to CCC, taken together, these statements show that it is unlikely that ComEd will need to access the capital market in the near future.

****128** CCC concludes that Mr. Bodmer's analysis showed that a leading investment bank recently concluded that a fair cost of equity for ComEd is 7.75%. CCC asserts that while ComEd claimed that Mr. Bodmer's analysis was speculative and subjective, its Cross Exhibit 6 (the Lehman Brothers letter), confirmed that Mr. Bodmer's recommended cost of equity is comparable to that determined by Morgan Stanley.

CCC added that the changes that have happened since ComEd's last DST rate case, including (1) lower personal tax rates, (2) lower overall interest rates, (3) lower ComEd business risks, (4) greater ComEd revenue stability if its residential rate design proposals are adopted and (5) fewer ComEd large distribution system capital investments in the near future - and ***281** Mr. Bodmer's market-to-book ratio analysis - all argue for adoption of Mr. Bodmer's direct and objective method for determining the appropriate cost of equity for ComEd.

Alternatively, if the Commission rejects Mr. Bodmer's recommendation, CCC recommends that these factors show that the Commission should adopt a cost of equity at the low end of the ranges submitted by the other cost of equity witnesses.

GDP Growth Rate

CCC argues that all witnesses other than Dr. Hadaway who testified regarding cost of common equity concluded that the ComEd witness' use of long-term gross domestic product (‘GDP‘) to estimate long-term growth expectations as part of his DCF analysis improperly inflated his DCF result. According to CCC because Dr. Hadaway testified that his primary cost of equity recommendation came from his DCF analysis (ComEd Ex. 8.0 at 16, L. 349-50), each witness concluded that Dr. Hadaway's cost of equity recommendation was overstated. CCC summarizes the criticisms by CCC witness Mr. Bodmer, Staff witness Mr. McNally and IIEC witness Mr. Gorman of Dr. Hadaway's approach as follows.

Mr. Bodmer - Mr. Bodmer described Dr. Hadaway's use of GDP growth rate as a proxy for dividend growth as wrong both from a theoretical and quantitative perspective. CCC Ex. 1.0 at 78, L. 2377-78. Mr. Bodmer pointed out that the authors of an article cited by Dr Hadaway to support his use of GDP (ComEd Ex. 8.0 at 28, L. 624-29) ‘criticize the use of analyst growth rates, but the criticism is that analyst growth rates are too high, not too low‘ and that the authors recommend use of a 3.5% GDP growth figure, which is significantly lower than the 6.6% figure used by Dr. Hadaway. CCC Ex. 1.0 at 78-79, L. 2402-11, *citing* Chan, L., Karceski, J. and Lakonishok, J., ‘The Level and Persistence of Growth Rates,‘ *Journal of Finance*, April 2003, p. 649. Most important, CCC stated that Mr. Bodmer testified that Dr. Hadaway's growth rate cannot be sustained. Using Dr. Hadaway's growth rate, his dividend payout ratio and the 32.7% retention rate of the companies in his sample would mean that the utility industry would have to average an astronomical 20.2% return on equity. CCC Ex. 1.0 at 79, L. 2424-32. CCC argued that such returns are not realistic.

****129** CCC adds that using a more reasonable growth rate and Dr. Hadaway's other assumptions in his DCF analysis yields cost of equity results comparable to Mr. Bodmer's 7.75% Morgan Stanley estimate.*Id.* at 70, L. 2119-29.

Mr. McNally - Mr. McNally testified that Dr. Hadaway's economy-wide 6.6% growth rate ‘is not a reasonable estimate of the sustainable growth of the individual companies in his samples.‘ Staff Ex. 5.0 at 20, L. 378-82. Mr. McNally added that ‘the GDP growth rate is more than two percentage points higher, an increase of almost 50%, than the highest of the other …estimates for either‘ Mr. Hadaway's local distribution company (‘LDC‘) or electric companies sample.*Id.* at 20, L. 387-89. CCC pointed out that similar to Mr. Bodmer, Mr. McNally testified that using Dr. Hadaway's 6.6% growth rate and the retention rates of his LDC and electric companies sample implies returns on equity of 20.54% for the LDC sample and 22.31% for the electric companies sample.*Id.* at 20-21, L. 392-405. Mr. McNally concluded that Dr. Hadaway's use of the GDP growth rate ‘leads directly to an overstated cost of equity estimate.‘*Id.* at 23, L. 456-57.

Mr. Gorman - Mr. Gorman testified that Dr. Hadaway's 6.6% historical GDP growth rate is out of line with economists' projections of GDP growth. Mr. Gorman stated that ‘consensus economists' projections of future GDP growth over the next five and ten years is 5.5%.‘ IIEC Ex. 3.0 at 41, L. 909-12, *citing* Blue Chip Economic Forecast, October 10, 2005. Mr. Gorman explained that Dr. Hadaway's use of historical GDP as a ***282** proxy for future growth rate is inappropriate because it overstates expected future inflation rates. IIEC Ex. 3.0 at 41-42, L. 913-18; March 29, 2006 Tr. at 2039-40.

CCC concluded that the respective testimonies of Messrs Bodmer, McNally and Gorman demonstrated that Dr. Hadaway's use of historical GDP as a proxy for future growth rate is not supportable and inappropriately inflates his cost of equity recommendation.

Investment Bank Analysis

As discussed in Section III.E.3 above, CCC witness Mr. Bodmer recommended that the Commission adopt a 7.75% cost of common equity for ComEd. Mr. Bodmer's recommendation was based on his analysis of the valuation conducted by Morgan Stanley of the ongoing Exelon-PSE&G merger.

CCC argues that the Commission should use Mr. Bodmer's investment bank analysis because it represents a more direct means for determining the appropriate cost of common equity for ComEd. CCC asserts that traditional methods for calculating a utility's cost of common equity are fraught with many subjective assumptions, are often opaque and difficult to understand and are designed to overcome significant evidentiary gaps that exist because it is extremely difficult to measure the level of return required by investors to provide capital for a company.

In contrast, CCC claims that Mr. Bodmer's investment bank analysis is a far more reliable indicator of investor needs than the traditional subjective models used by ComEd witness Hadaway, Staff witness McNally and IIEC witness Gorman. CCC added that in determining ComEd's cost of common equity, the investment banks and the Commission share a common goal - to establish ‘the opportunity cost that measures required returns for investments of similar risk.‘*Id.* at 17, L. 503-05.

****130** CCC also argues that investment banks have no bias when conducting valuations. According to CCC, investment banks are in a highly competitive business that requires them to keep abreast of new research and to innovate quickly to insure that their valuations are accurate. Failing to determine accurately a company's cost of equity can result in a merger not taking place or, alternatively, acquisitions to be over-priced. CCC Ex. 4.0 at 5, L. 149-54. CCC asserts that traditional methods for estimating a company's cost of equity do not face the same level of real world scrutiny. The CAPM and DCF models are subject to manipulation in terms of selection of financial data used and modeling approaches. CCC Ex. 1.0 at 5, L. 125-26. CCC posits that the persons applying the CAPM and DCF models often are pursuing an agenda that calls into question the impartiality of their analysis. For example, ComEd paid Dr. Hadaway a substantial sum of money to present his cost of common equity testimony. CCC Ex. 4.0 at 6, L. 182-85. As Mr. Bodmer noted, for this sum of money, one can expect that ‘ComEd will get the most aggressive arguments possible to support a high return on equity.‘*Id.* at 6, L. 185-86.

CCC argues that recent research demonstrates that the CAPM and DCF models overstate a company's cost of common equity. As to the CAPM model, CCC claims that research indicates that the use of actual realized returns in the market risk premium that is used as an input in the CAPM model inflates a company's required cost of equity. CCC Ex. 1.0 at 16-17, L. 469-89.

As to the DCF model, CCC states that research shows that estimating the cost of equity using analyst growth forecasts in the DCF model results in a cost of equity that is too high. CCC Ex. 1.0 at 15-16, L. 448-49, 454-56. According to a study cited by ComEd witness Dr. Hadaway, analyst ‘growth forecasts are overly optimistic and add little predictive power.‘ City Ex. 1.0 at 16, L. 458-60, *citing* Chan, L., Karceski, J. and Lakonishok, J., ‘The Level and Persistence of Growth Rates,‘ *Journal of Finance*, April 2003, p. 643.

CCC argues that the body of growing research showing that the CAPM and DCF models overstate the required cost of equity for utilities argue for adoption of Mr. Bodmer's investment bank analysis, which represents a ***283** more direct and objective method for determining the appropriate cost of equity for ComEd.

Market to Book Ratio

CCC argues that Mr. Bodmer tested his position that traditional methods for measuring a company's cost of capital overstate the needs of investors by analyzing the market to book ratios of 71 utility companies. CCC Ex. 1.0 at 42-43, L. 1277-87; CCC Ex. 1.04. CCC states that it is commonly accepted that a company earning its expected cost of capital has a market to book ratio of one. CCC Ex. 1.0 at 42, L. 1256-58. If a company's market to book ratio is above one, it is earning in excess of its expected rate of return. Conversely, if a company's market to book ratio is below one, it is earning less than its expected rate of return. CCC Ex. 1.0 at 42, L. 1261-64.

****131** CCC asserts that Mr. Bodmer's analysis of the 71 utilities found that on average, these companies have a market to book ratio of 1.75. That is, these utilities are earning in excess of their allowed cost of capital.*Id.* at 43, L. 1286-87; CCC Ex. 1.04. CCC states that Exelon - ComEd's parent corporation - had the highest market to book ratio of all of the utility companies analyzed - 3.38. CCC Ex. 1.0 at 43, L. 1285-86; CCC Ex. 1.04. CCC pointed out that no party challenged Mr. Bodmer's conclusions on these points.

CCC avers that Mr. Bodmer's graph of market to book ratios and returns on equity for the 71 companies examined showed a strong positive relationship between a utility's market to book ratio and its return on equity. CCC Ex. 1.0 at 43, L. 1298-99, 1307-17. CCC added that Mr. Bodmer's regression analysis on the information presented in his graph showed that the only significant variable affecting market to book values is the cost of equity.*Id.* at 44, L. 1329-30. That is, a higher the cost of equity translates into a higher market to book value.

CCC concluded that Mr. Bodmer's analysis invalidated ComEd witness Dr. Hadaway's risk premium approach. *Id.* at 45, L. 1363. According to CCC, if Dr. Hadaway's approach were valid, the utility commission rates of return he included in his analysis would have market to book ratios nearing one.*Id.* at 45, L. 1365-67. According to CCC Mr. Bodmer's analysis showed that the market to book ratios have consistently been far above one. CCC argues that this confirms Mr. Bodmer's point that utility commissions have been setting returns in excess of utilities' actual cost of capital.*Id.* at 45, L. 1367-70.

IIEC

IIEC argues ComEd overestimated its required return on common equity when it requested an authorized equity return of 11%. IIEC, through its witness Mr. Gorman, recommended a return on common equity (‘ROE‘) of 9.9%, which Mr. Gorman found adequate to support ComEd's credit rating and its financial integrity.

IIEC's recommendation was based on Mr. Gorman's multi-faceted analysis, which considered the results of a constant growth discounted cash flow model (‘DCF ‘), a risk premium model (‘RP‘), and a capital asset pricing model (‘CAPM ‘). IIEC's recommendation is based on these results of Mr. Gorman's models: DCF (9.7%); RP (10.2%); and CAPM (10.2%). According to IIEC these three analytical models, each of which was used by at least one other ROE witness in this case, have been employed regularly in Illinois regulatory proceedings.

IIEC states ComEd's witness Dr. Hadaway, also conducted multiple studies, but IIEC says virtually every cost estimate made by Dr. Hadaway was overstated and flawed. IIEC asserts that its witness Mr. Gorman showed that using reasonable estimates, and excluding Dr. Hadaway's unreasonable add-on premiums, Dr. Hadaway's own analysis would support a return on equity under 10.0% as reasonable for ComEd.

IIEC argues the DCF model posits that a stock is valued by summing the present value of its expected future cash flows, discounted at the investor's required rate of return (‘ROR‘) or cost of capital. The model's basic

equation can be arranged to estimate the investor required ***284** return on an equity investment. The constant growth rate DCF model, which assumes dividends grow at a constant rate, is expressed mathematically as follows:
****132** K = D1/P0 + G where:

K = the investor's required return;

D1 = dividends in the first year;

P0 = current stock price; and

G = expected constant dividend growth rate.

IIEC says the primary disputed DCF model input in this case is the growth rate. To estimate ‘G‘ (the expected constant growth in dividends), IIEC witness Gorman used the consensus estimate of investment analysts of the expected growth rate. With this input, his constant growth DCF model yielded a range of 9.3% to 9.4% for the return on common equity. Mr. Gorman selected 9.4% from that range as his DCF return on common equity. Consistent with past Commission practice, Mr. Gorman then adjusted the results of his constant growth DCF formula to recognize quarterly compounding. As adjusted, his DCF analysis produces a recommended return on common equity of 9.7%.

IIEC opines that in ComEd's view, the alleged problem with Mr. Gorman's analysis can be traced to his sole reliance on analysts' growth rate estimates to determine the growth rates for his DCF model, giving no weight to long-term growth forecasts. However, Mr. Gorman explained that security analysts' growth estimates have been shown to be more accurate predictors of future returns than growth rates derived from historical data and are the most likely growth estimates that are built into stock prices.

IIEC asserts that Mr. Gorman's consensus analysts' growth rates (4.67% and 4.42%) for the proxy groups he and ComEd used were reasonably consistent with five-year projected GDP growth of 5.3%, and considerably higher than the five-year projected GDP inflation growth of 2.4%. Utilities' dividend growth cannot sustain a growth rate exceeding the growth rate for the economy. Therefore, growth rates for the economy in the utility's service territory are a good proxy for a sustainable long term growth rate for earnings.

IIEC says Mr. Gorman used a conservatively high growth estimate, based on virtually every logical and verifiable assessment of long-term sustainable DCF growth. He describes the input as conservative because historically these utilities' dividend growth have not exceeded the rate of inflation, projected growth but his analysis approaches two times the projected rate of inflation of 2.5%. IIEC says Mr. Gorman was conservatively high because historically, utility earnings and dividends have grown at a rate much slower than GDP growth.

IIEC says Mr. Gorman's conservative growth variables reflect the conditions most likely to prevail while the rates determined in this case will be in effect. It reasons that over the longer term, ComEd is unlikely to suffer inadequate returns, since the utility can be expected to file for changes in its authorized return and its delivery service rates if there is a significant variance from current growth projections.

On the other hand, IIEC says, ComEd's proposed analysis uses historical data that unreasonably denies its customers any benefit of today's (and likely tomorrow's) reality. IIEC says the Commission should accept Mr. Gorman's analysis estimating ComEd's required return on common equity.

****133** IIEC also points out its witness used a risk premium model in estimating ComEd's required return on equity. The risk premium model is based on the principle that investors require a higher return to assume a greater risk. Common equity is viewed as having greater risk than corporate bonds. Under the RP model, the risk premium representing the greater risk of equity in comparison to bonds may be calculated in two different ways: (a) as the difference between the required return on utility common equity investments and a U.S. Treasury bond; and (b) as the difference between the return on equity approved for utilities by regulatory commissions***285** and the return on contemporary utility bonds. IIEC says its witness, Mr. Gorman, used both methods and developed an RP return on common equity recommendation of 10.2%, which was considered along with his DCF and CAPM model results in determining his final ROE recommendation.

IIEC says ComEd questioned Mr. Gorman's analysis because he declined to make several baseless adjustments that inflate Dr. Hadaway's RP Estimate. Mr. Gorman used a combination of current and projected interest rates. Dr. Hadaway relied entirely on projections according to IIEC. IIEC says ComEd's reliance on projections is misplaced because the accuracy of projected interest rates is highly problematic. In addition, IIEC says Dr. Hadaway increased his claimed equity risk premium from 3.08% to 4.4% based on an alleged inverse relationship between interest rates and risk premiums, thus increasing ComEd's recommended equity cost. Mr. Gorman rejected this adjustment because it has been shown to be questionable by academic studies. IIEC also states Mr. Gorman relied on actual observable bond yields, while Dr. Hadaway's RP study used his own idiosyncratic projection of bond yields. IIEC argues Mr. Gorman's RP analysis is more reasonable and merits the Commission's reliance.

IIEC states that Mr. Gorman's use of a combination of projected and current, observable interest rates was carefully considered and fully justified. It says Mr. Gorman conducted an extensive analysis of interest rate data to answer the question whether the Commission should follow Dr. Hadaway's lead and accept interest rate projections over ‘observable and verifiable‘ interest costs. While projected interest rates should be given some consideration, the determination of ComEd's cost of capital today should be based primarily on observable and verifiable actual current market costs, because projected changes to interest rates are highly uncertain and the accuracy is at best problematic. Mr. Gorman chose to be conservative in his analysis by considering both current and projected interest rates, thus reflecting a range of possible interest rates during the period rates set in this proceeding are in effect.

IIEC says considerable protection against increasing costs of capital is inherent in a utility's right to initiate ratemaking proceedings. This provides an effective hedge against increasing costs and is additional reason why there was no need to inject uncertain capital costs into rates. IIEC argues the Commission can be confident that ComEd will act if actual interest rates diverge significantly from current projections. Accordingly, IIEC says Mr. Gorman's RP model, which recognized the reality of today's economic conditions and today's investor's expectations should be accepted as the superior analysis by the Commission.

****134** IIEC says its witness Mr. Gorman also performed a CAPM analysis, which is a specialized form of risk premium analysis. Mr. Gorman developed a CAPM analysis as well as DCF and bond yield RP analyses. According to IIEC, Mr. Gorman's CAPM results varied only modestly from his other models; in fact, his CAPM and RP results were identical.

IIEC opines that Mr. Gorman's CAPM results were also well inside the range defined by the CAPM result extremes of CUB on the low end and Staff on the high end. Accordingly, IIEC says the debate on CAPM issues has focused on other witnesses' application of this model.

Commission Analysis and Conclusion

[61-64] ComEd asserts its cost of equity should reflect the costs of equity recently approved for electric utilities in the United States. The cost of equity appropriate to ComEd, however, is specific to that utility. ComEd may not simply adopt the cost of equity set for other utilities scattered around the country, for which the facts and circumstances are not necessarily similar. Rather, pursuant to Section 9-201 of the Act, ComEd must prove that its proposed cost of equity is just and reasonable.

ComEd also asserts that it faces additional financial risk if it does not receive its requested capital structure. The Commission disagrees that the just and reasonable capital structure ***286** imposes extra risk on the Company, regardless of whether it is the one proposed by ComEd or another.

The parties have raised three considerations that impact their respective estimates. We turn first to those issues.

The first is whether ComEd's use of GDP growth rates to estimate long-term growth expectations of individual companies in the DCF model improperly overestimates the model's results. ComEd asserts that GDP growth rates should be used to model long-term growth for the DCF analysis. Staff, CCC, and IIEC criticize ComEd's approach.

Staff states that ComEd's inappropriate application of the economy-wide GDP growth rate as an estimate of the growth of the individual companies in the samples being modeled accounts for almost all of the difference between the cost of equity estimates advanced by Staff and ComEd. Staff points out that ComEd witness Hadaway's 6.60% GDP growth rate is 200 to 300 or more basis points higher than the expected company-specific growth rates for the companies in his samples. Furthermore, the application of the economy-wide GDP growth rate assumes that the utilities will grow at the same rate, but the empirical evidence suggests below-average growth based on below average risk shown by betas of less than 1.00. Staff also contends that, even if GDP growth rates were accepted as a general matter, ComEd's rate of 6.60% is unsustainable and overstated compared to published GDP growth expectations cited by Staff and IIEC.

CCC argues that ComEd witness Hadaway used an unsustainable 6.60% rate of GDP growth, that this vastly overstates their cost of equity, and implies returns on equity in excess of 20%. IIEC extends this by observing that utility earnings and dividends grow substantially more slowly than GDP growth. Furthermore, IIEC points out that ratepayers bear the risk of exaggerated rates under ComEd's proposal, while the Company may seek rate relief in the event that there is a significant variance from current growth projections.

****135** The Commission finds that the use of GDP growth rates to estimate long-term growth leads to an improper and overstated estimate of the cost of capital. Furthermore, the Commission does not find merit in the Company's assertion that a five-year period fails to adequately consider long-term growth expectations. Accordingly, ComEd's use of GDP growth rates is rejected.

The second issue concerns CCC's use of investment bank analysis in calculating the cost of equity for ratemaking purposes. CCC witness Bodmer analyzed the valuation conducted by Morgan Stanley and other investment banks for the ongoing merger of Exelon and PSE&G, and used this as a basis for his 7.75% cost of equity recommendation. CCC alleges that the investment bank analysis provides a more direct assessment of the cost of equity for ComEd, and that it is not subject to the assumptions made in modeling the cost of equity of a non-traded subsidiary such as ComEd. Finally, CCC contends that the CAPM and DCF models can be manipulated, while the competitive market in which the investment banks compete forces their analyses to be unbiased.

ComEd asserts that CCC's use of investment bank analysis for use in calculating a discount rate for ratemaking purposes is not appropriate due to various methodological differences that do not necessarily estimate the utility's reasonable return on rate base. Staff concurs that the investment bank cost of equity estimates are inappropriate due to a variety of assumptions with respect to the instant case that may or may not match those used by the banks themselves.

The Commission agrees with ComEd and Staff that, for purposes of this case, the problems inherent with the use of the investment bank analyses outweigh their contribution to the entire body of evidence.

The third issue concerns CCC's theory for the market-to-book ratio. CCC alleges that companies earn exactly their cost of capital when the market-to-book ratio is 1.00. CCC further contends that their analysis of 71 utilities shows they typically earn more than their cost of capital, and ComEd parent Exelon earns most of all.

Staff criticizes CCC's theory, asserting that it is oversimplified and not readily applicable. ***287** Staff notes that certain ratemaking practices can account for variation in the market-to-book ratio, so a ratio in excess of 1.00 is not necessarily too high. Staff also points to a wide range of risk in the 71 companies analyzed, implying a range of required rates of return rather than a uniform cost of equity derived from a single 'correct' market-to-book ratio. Finally, Staff avers that the components of the market-to-book ratio are inconsistent in terms of time and construction, rendering application for ratemaking problematic. ComEd also criticizes CCC for suggesting that the cost of equity should reflect the market-to-book ratio. ComEd points out that there are legitimate reasons for variance from market-to-book, and that such variance does not necessarily signify over-earning by the utility.

****136** The Commission declines at this time to impose a strict market-to-book regime in the determination of the cost of equity. The Commission believes that such a model is too inflexible and may not adequately reflect a utility's cost of equity. Accordingly, it is rejected.

In light of the determination of the foregoing issues, the Commission finds that the ComEd proposal is excessively high due to its improper application of the GDP growth rates, and the CCC proposal is inadequately low due to its application of the latter two issues just rejected. This leaves the proposals of Staff and IIEC. The Commission notes that the results of the analyses produced by Staff and IIEC are relatively close, and that the amount of argument from either against the other is minimal. Although the Commission has rejected the CCC proposal in this case, the Commission finds the observed equity return requirements of ComEd's investment banks compelling. Therefore, the Commission finds that the CCC analysis justifies adoption of a cost of equity in the lower portion of the range of reasonable return levels for ComEd. Accordingly, the Commission adopts a 10.045% cost of equity, which is slightly lower than Staff's proposal of 10.19%.

4. APPROVED RATE OF RETURN ON RATE BASE

[65] Upon incorporation of the conclusions stated above, the Commission finds that ComEd's capital structure and cost of capital, resulting in overall cost of capital of 8.01% may be summarized as follows:

Class of Capital	Proportion	Cost	Weighted Cost
Long-term debt	57.14%	6.48%	3.70%
Common Equity	42.86%	10.045%	4.31%
	____		____
TOTAL	100.00%		8.01%

The Commission finds that this overall cost of capital to be reasonable and should be used for purposes of ComEd's authorized rate of return on rate base in this proceeding.

VI. COST OF SERVICE ISSUES

1. EMBEDDED COST OF SERVICE STUDY

ComEd

[66-69] ComEd presented an embedded cost of service study ('ECOSS'), which for purposes of this proceeding, allocated Distribution-and Customer-related costs to retail delivery classes and developed the appropriate unit costs. Heintz Dir., ComEd Ex. 11.0, 5:90-102. ComEd notes that subject to certain appropriate adjustments, the ECOSS' input costs generally are the same costs booked to ComEd's accounts in the test year.*Id.*

According to ComEd, there are two types of cost studies filed in utility rate cases: an ECOSS, which utilizes historical relationships among booked costs and the volumes of services delivered by the utility; and a marginal cost of service study, which employs analyses and estimates of incremental changes in costs, as these changes are related to (caused by) incremental changes in volumes of services forecasted to be delivered in the future.*Id.* at 5:98-102.

ComEd notes that it used an ECOSS in prior rate case proceedings before the Commission,***288** primarily to determine the jurisdictional revenue requirement.*Seee.g.* , Orders, ICC Dockets 90-0169, 94-0065, 99-0117, and 01-0423. Heintz Dir., ComEd Ex. 11.0, 5:103-07. ComEd also notes that for purposes of establishing delivery service charges, ComEd generally supports the use of a marginal cost of service study. Crumrine Dir., ComEd Ex. 9.0 Corr., 43:925-36. ComEd explains, however, that in light of the Commission's approval and use of an ECOSS in the last two ComEd delivery services rate cases (ICC Dockets 99-0117 and 01-0423), and in the interest of narrowing the issues in this case, it proposes the use of an ECOSS for both interclass revenue allocation and rate design purposes.*Id.* Notwithstanding this proposal, ComEd notes that it continues to reserve the right to propose the use of a marginal cost study in future proceedings.*Id.*

****137** ComEd argues that the basic structure and functioning of the ECOSS submitted in this proceeding is substantially similar to ComEd's ECOSSs filed and approved in ICC Dockets 99-0117 and 01-0423. Heintz Dir., ComEd Ex. 11.0, 6:108-13.

Staff

Staff does not object to ComEd's embedded cost of service study. (ICC Staff Exhibit 6.0, pp. 35-36) An embedded cost of service study functionalizes and classifies the utility's costs for Production (if any), Transmission, Distribution, and Customer-related (‘P-T-D-C‘) functions. (ComEd Ex. 11.0, p. 5) ComEd proposes to allocate costs among rate classes in a manner that is similar to what was approved by the Commission in its previous delivery service rate cases. (*Id.*, p. 6) Staff finds no issue that would prevent its acceptance for ratemaking purposes; therefore, Staff does not object to the study. (ICC Staff Exhibit 6.0, p. 36)

CUB-CCSAO-City

CCC maintains that ComEd's embedded cost of service study (‘ECOSS‘) improperly fails to take into account both class peak and average (‘P&A‘) demand in allocating distribution demand costs among the rate classes. Because ComEd is a wires only distribution utility, CCC contends that investments in the distribution system are justified by revenue from both peak and annual usage. CCC notes that Steven Ruback and ComEd witness Hadaway both testified that distribution-only electric utilities are structurally similar to natural gas local distribution companies (‘LDCs‘) regulated by the Commission. Therefore, Mr. Ruback asserted that the Commission's approach to distribution cost of service in this case should be consistent with its approach to LDCs' cost of service, and should, accordingly, be based on average annual usage as well as peak demand. CCC notes that the Commission has followed this in every natural gas distribution rate case in the last ten years. CCC Initial Br. at 38-39.

CCC further contends that there is an economic justification for allocating ComEd's distribution demand costs partly on average utilization of distribution facilities: ComEd's distribution system would not be built if the utility's investment in the system could not be recovered through revenue from annual as well as peak usage. In particular, Mr. Ruback testified that revenues from kilowatt-hour charges, which reflect average rather than peak usage, represent approximately one-third of ComEd's proposed revenue requirement, a share comparable to the roughly 42 percent of ComEd's revenue requirement attributable to revenue from demand (kilowatt) charges. Moreover, CCC continues, allocating distribution demand costs, which are fixed, on the basis of peak demand is inconsistent with ComEd's proposed allocation of the Supply Administration Charge - a charge that ComEd proposes to allocate based on average demand even though it does not vary based on energy usage. Mr. Crumrine asserted that this allocation method is appropriate because, conceptually, they are incurred to provide supply to customers. ComEd Ex. 9.0 (corrected) at 47, L. 1022-23. Accordingly, CCC maintains that because distribution facilities are used to provide for the local delivery of power and energy, distribution demand costs should also be allocated based partly on energy usage. ***289** To do this, Mr. Ruback applied a peak and average ('P&A') method that weighted each type of demand equally, noting that the Commission, in the exercise of its discretion, may assign different weighting to demand and annual sales.

BOMA

****138** As discussed further below in Sections II.H.3. Revenue Allocation - Other and II.I.1.b)2) Very Large Load Customers, BOMA takes the position that ComEd's embedded cost of service study should not be used to allocate any revenue requirement increase [or decrease] for nonresidential consumers because the embedded cost of service study only allocates costs based on ComEd's proposed nonresidential customer classes rather than ComEd's existing nonresidential customer classes. FN21(Trans., pg. 2242, ln 12 pg. 2243, ln. 1). In addition, BOMA contends that ComEd's embedded cost of service study also is flawed because it classifies all distribution plant and associated costs in FERC accounts 364-368 as solely demand-related and it uses inappropriate weighting factors in its allocation of certain costs. (BOMA Ex. 2.0, pg. 14, ll. 309-324; BOMA Ex. 4.0, pg. 8, ll. 184-192). These two points are further described below in Sections II.G.2. - Minimum Distribution System and II.G.4.a) Weighting Factors.

BOMA recommends that rather than utilizing ComEd's embedded cost of service study to allocate the revenue requirement increase (or decrease) in this proceeding for nonresidential customer classes, the Commission should retain ComEd's existing nonresidential delivery service customer classes and allocate any revenue requirement increase (or decrease) to nonresidential customers on an equal percentage, across-the-board basis to these existing customer classes. (BOMA Ex. 4.0, pg. 7, ll. 167-171; BOMA In. Br., pg. 10-11).

DOE

DOE states that ComEd proposes to redesign its nonresidential customer class definitions in this case. ComEd proposes to combine all standard voltage customers with loads above 1,000 kW into one class, whereas these customers are currently divided into four classes. DOE says those four classes currently include all customers with loads at high voltage levels, defined as at or above 69 kV, and these high voltage loads are currently provided a discount under Rider HVDS.

According to DOE, under ComEd's proposed class definitions, all high voltage customers, regardless of size, would be placed into one class. A fixed Distribution Facilities Charge (DFC) of $2.17 is proposed by the Company to apply to all high voltage customers. DOE asserts that this approach results in significant reductions in the DFC for high voltage customers with loads up to 10,000 kW, and an enormous increase of 160 percent for high voltage customers with loads in excess of 10,000 kW.

DOE says these new non-residential class definitions were used to determine class cost responsibilities in the Company's ECOSS. According to DOE, the High Voltage Class, defined as 69 kV and above, actually includes loads that are served at voltages less than 69kV. DOE suggests that the Company has, for purposes of determining the costs to be allocated to this class, included the loads of some customers that are served at lower voltages as long as those customers have some load served at 69 kV or above. Since there are some loads served at distribution voltages in this 'high voltage' class, costs associated with three categories of distribution facilities are allocated to this High Voltage class: (1) High Voltage Distribution Substations; (2) Distribution Substations: and (3) Distribution Lines. DOE argues that this procedure results in more than 25 percent of the facilities costs allocated to the High Voltage class accounted for by facilities that virtually provide service only at delivery points served below 69 kV. DOE complains that under ComEd's proposal customers at or above 69 kV would end up paying for these.

****139** DOE argues that ComEd's approach embodies a cross-subsidy from those customers that have only high voltage loads to those that have low voltage loads. DOE claims the average ***290** cost per kW for those loads at or above 69 kV is $1.72 and for those loads below 69 kV is $6.11. DOE suggests the cross-subsidy from combining the rate for both low and high voltage loads amounted to approximately $4 million.

DOE recommends that, if the Commission determines that average embedded costs should be mechanistically translated into rates, a procedure that DOE takes issue with, then the Commission should, at the very least, use the High Voltage Class modification to the Company's ECOSS proposed by Dr. Swan. DOE says the implication for rates would be either to have two classes of High Voltage loads, or to place low voltage loads included by the Company in the High Voltage Class in the appropriate standard voltage category. According to DOE, ComEd could bill those loads based on standard voltage rates. DOE claims this is essentially what happens under the current system of providing a high voltage credit to the standard voltage rate on that portion of the demand that qualifies for the high voltage discount served at 69 kV or above. The Company has raised billing complication objections to this approach, which DOE believes are without merit.

IIEC

IIEC notes ComEd recommended the use of an embedded cost of service study (‘ECOSS‘) in this proceeding for rate design and revenue allocation purposes. However, the study presented by ComEd did not provide information on the cost to serve the existing non-residential customer classes and it did not adopt the concept of the minimum distribution system.

Because the Company's ECOSS did not provide information on the cost of serving the existing non-residential classes, IIEC argues it cannot be used to justify the combination of those classes into a single class. Nor can it be used for rate design for the 10 MW and over class, which IIEC, therefore, recommends be retained as discussed in Section III.H.1.b.(2).(a) below. IIEC reasons that because the Company's ECOSS does not reflect the minimum distribution concept, the study overallocates costs to the Very Large Load Class. Therefore, IIEC recommends ComEd be directed to present a study incorporating the minimum distribution concept in its next delivery service rate case. (*See,* Sec. III.F.2. below). In addition, IIEC recommends that the Commission reject proposals to arbitrarily allocate 50% of the cost of the distribution system on the basis of kilowatt hours (‘kWh‘) used.

Commission Analysis and Conclusion

ComEd's ECOSS appears to have been performed in a manner similar to the study utilized for certain purposes in Docket 01-0423.In that case, the ECOSS was utilized to allocate the jurisdictional revenue requirement responsibility between the residential and nonresidential rate classes. In the instant proceeding, while IIEC, BOMA and to some extent the DOE are critical of ComEd's ECOSS, there does not appear to be an objection to using ComEd's ECOSS for that purpose. Thus, the Commission concludes that ComEd's ECOSS will be used to allocate jurisdictional revenue requirement responsibility between the residential and nonresidential rate classes.

****140** Except to the extent necessary to comply with other findings in this Order, the Commission adopts ComEd's ECOSS for purposes of designing rates in this proceeding. Before moving on to other contested issues, the Commission notes that as discussed more thoroughly elsewhere in this Order, the Commission takes seriously certain public policy considerations such as energy conservation and the impact utility rates can have on energy consumption and the environment. As a result, while ComEd did not present a marginal cost of service study in this proceeding, the Commission would be interested in whether any party believes that considering marginal cost of distribution service has any place in setting electric distribution rates. The Commission invites parties to address this subject in ComEd's next rate case.

2. MINIMUM DISTRIBUTION SYSTEM

ComEd

***291 [70-72]** ComEd states that the cost causation methodology underlying its ECOSS is consistent with the ECOSS submitted in its two previous delivery service rate cases. ComEd explains that consistent with that accepted methodology, and the Commission's Orders approving those prior ECOSSs, ComEd's ECOSS does not reflect a minimum distribution concept. (Heintz Reb., ComEd Ex. 25.0 2:27- 29.)

ComEd notes that the Commission has in the past soundly rejected the minimum distribution system and zero-intercept concepts advocated by IIEC and BOMA, and argues that the Commission should do the same here. ComEd cites ICC Dockets 990121 and 00-0802 as examples where the Commission rejected these concepts. In those dockets, according to ComEd, the Commission rejected Ameren's proposal to employ the zero-intercept method of identifying the portion of distribution costs said to be related to connecting customers to the system, so that these costs could be allocated to customer classes on a basis other than demand, and charged through a customer charge.*See Central Illinois Public Service Co.*, ICC Docket 00-0802 (Order, Dec. 11, 2001). ComEd notes that in that case, the Commission agreed with Staff, finding that:

[a] utility's system is designed in an integrated manner to deliver electricity to customers in quantities to meet all customer demands and individual components of the system cannot be identified for purposes of connecting customers only.

(*Id.* at 42). ComEd also notes that in rejecting Ameren's proposal and accepting Staff's method, the Commission stated:

[i]n the Commission's view, Staff's method is consistent with the fact that distribution systems are designed primarily to serve demand, and the Commission agrees with Staff that attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic.

(*Id.*)

ComEd further explains that the minimum distribution system and zero-intercept concepts are attempts on the part of IIEC and BOMA to shift costs away from non-residential customers to residential customers. (Heintz Reb., ComEd Ex. 25.0, 7:142-47).

Staff

****141** Staff challenges the minimum system to allocate distribution costs (‘minimum distribution system‘) proposed by Alan Chalfant (IIEC Exhibit 2.0) and David McClanahan (BOMA Exhibit 2.0). According to Staff, the minimum system is a flawed concept that the Commission has consistently rejected in the past.

Staff argues that the minimum system is a flawed concept that relies on a distant relationship between distribution costs and the number of customers as a basis for shifting costs from the demand to the customer function and, thereby, benefits large customers at the expense of smaller customers on the system. According to Staff, it is true that an important function of the distribution system is to connect customers to the system. However, the most relevant factor in determining the costs of connection is not the number of customers, but rather the location of customers within the utility's service territory. Staff points out that the cost of connecting one rural customer may be far higher than connecting a dozen customers in a multifamily dwelling in an urban setting. Staff argues that differences such as this undermine the use of the number of customers as a determinant of distribution plant costs. (ICC Staff Exhibit 17.0 Corrected, pp. 40-41)

Staff also cites hearings in which the Commission has rejected the allocation of distribution costs on a customer basis (*See* Order, Docket No. 01-0444 (MidAmerica), p. 19 (March 27, 2002); Order, Docket No. 00-0802 (Ameren), pp. 42-43 (Dec. 11, 2001); and Order, Docket No. 99-0121 (CIPS), p. 71 (Aug. 25, 1999)) since that manual was written in January 1992 (BOMA Ex. 2.0, p. 13). Moreover, Staff points out that no electric or gas utility in Illinois currently employs a minimum system to ***292** allocate costs among customer classes. (ICC Staff Exhibit 17.0 Corrected, p. 41)

Staff also argues that the BOMA witnesses have not explained how the minimum distribution system would be implemented, and therefore, the Commission does not have an accurate understanding of what BOMA is really proposing.

Staff recognizes that BOMA is recommending that ComEd 'recognize a minimum distribution component in its next delivery service rate case or, at the very least, make available to parties the results of either a zero intercept analysis or minimum system study of its distribution Accounts 364 through 369. ' (IIEC Exhibit 2.0, p. 15) Staff's response is that BOMA's proposal should be rejected because the minimum system is flawed by nature and should not be used in this or any future rate proceedings. (ICC Staff Exhibit 17.0 Corrected, p. 42)

AG

The AG argues against employing the minimum distribution study ('MDS '), proposed by IIEC witness Chalfont, in determining just and reasonable rates citing three reasons. First, the AG notes that the Commission has consistently rejected MDS over the last 15 years.*Central Illinois Public Service Co. and Union Electric* Co., Docket No. 00-0802, 214 PUR 4th 437 (2001); *Central Illinois Public Service*, Docket No. 99-0121, 1999 Ill. PUC LEXIS 646 (1999); *Peoples Gas Light and Coke Co.*, Docket No. 91-0586, 1992 Ill. PUC LEXIS 376 (1992); *Illinois Power Co.*, Docket No. 91-0335, 1992 Ill. PUC LEXIS 267 (1992); *Commonwealth Edison Co.* , Docket No. 90-0169, 1991 Ill. PUC LEXIS 99 (1991); *Illinois Power Co.*, Docket No. 90-0006, 117 PUR 4th 418 (1990); *Northern Illinois Gas Co.*, Docket No. 88-0277, 103 PUR 4th 290 (1989). According to the AG, the Commission's rejection of MDS is addressed in the following order language:

****142** [D]istribution systems are designed primarily to serve electric demand, and the Commission agrees with Staff that attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic. Furthermore this conclusion is consistent with decision in recent cases …(*Central Illinois Public Service Co. and Union Electric* Co., Docket No. 00-0802, 214 PUR 4th 437 (2001)).

Second, the AG asserts that the concept of a 'minimum' distribution system, unrelated to energy consumption, is entirely theoretical and bears no relationship to the actual cost incurred by utilities to serve actual customers. The Commission directly cited this defect in a previous ComEd case, holding:

Edison objected to Mr. Corbin's suggestion that Edison perform a minimum distribution study …Edison also contended that little useful information would be gained from further analysis for the following reasons: 1) the determination of what constitutes a minimum distribution system is almost entirely arbitrary; and 2) such an analysis is highly theoretical and bears no relationship to any utility's actual engineering practices. Real systems are built to accommodate expected rather than minimum loads.

The Commission agrees with Edison that performing a minimum distribution system analysis would require substantial time and resources, but would produce no commensurately worthwhile results.*Commonwealth Edison Co.*, Docket No. 90-0169, 1991 Ill. PUC LEXIS 99 (1991) (emphasis added).

The AG argues that assuming a zero-use customer would be connected to the distribution system, as Mr. Chalfont did, is not realistic. According to the AG, a customer will connect to the system to use electricity, and the utility will incur costs based on the customer's anticipated demand for electricity.

Finally, the AG argues that Mr. Chalfant failed to quantify the impact of his MDS proposal. AG witness Rubin estimated that Mr. Chalfant's MDS proposal 'would result in enormous***293** shifts in cost allocation among customer classes' that would nearly double the level of rate increase proposed by ComEd for the residential classes, and more than triple the rate increase for the watt-hour class. The AG argues that the nonresidential small load, medium load, large load and very large load classes would be the beneficiaries of this shift in cost, where rates for the small load and medium load customers, proposed to increase by $15.7 million and $29.9 million respectively, would actually decrease below current rates under Mr. Chalfant's proposal. The

AG further asserts that this cost allocation bares absolutely no relationship to the actual cost incurred to design and construct ComEd's distribution system.

The AG supports ComEd's proposed method of allocating distribution lines and transformer costs on the basis of customer demand as fully consistent with Commission precedent, fully consistent with the way in which distribution systems are designed and constructed, and directly related to the way in which customers use the distribution system.

BOMA

****143** BOMA witness McClanahan testified that ComEd's embedded cost of service study does not comply with guidelines published by the National Association of Regulatory Utility Commissioners (‘NARUC‘) with respect to FERC accounts 364-368 because ComEd's cost of service study classifies all distribution plant and associated costs in these accounts as solely demand-related and thereby ignores the customer-related portions of these accounts. (BOMA Ex. 4.0, pg. 8, ll. 184-192; ComEd Ex. 11.1, Schedule 1b). Mr. McClanahan further testified that the operating electric utilities of Southern Company never failed to consider the customer-related component of distribution system costs associated with FERC accounts 364-368 during his thirty years of cost of service experience with Southern Company. (BOMA Ex. 4.0, pg. 8, ll. 189-192). Mr. McClanahan argued that the determination of the proper amount of customer related costs is critical to the accurate classification of these costs and the development of a cost-based customer charge. (BOMA Ex. 2.0, pg. 14, ll. 304-306). According to BOMA, ComEd never disputed Mr. McClanahan's testimony that ComEd's embedded cost of service study does not comply with NARUC guidelines with respect to FERC accounts 364-368. (BOMA Ex. 4.0, pg. 8, ll. 192-194).

BOMA takes the position that the Commission need not order ComEd to correct its cost of service study in this proceeding if the Commission orders ComEd to allocate any revenue requirement increase [or decrease] to non-residential customers on an equal percentage, across-the-board basis to ComEd's existing nonresidential customer classes. However, BOMA's position is that the Commission should order ComEd to follow the NARUC guidelines for allocating costs in FERC accounts 364-368 in ComEd's cost of service study presented in ComEd's next delivery services rate case.

IIEC

It is IIEC's position that ComEd's ECOSS departs from an accurate representation of cost causation because it does not include a customer cost component based on the minimum distribution system concept. While IIEC recognizes this concept has not been adopted by the Commission in the past, IIEC says it is a concept that is fully recognized by the National Association of Regulatory Commissioners (‘NARUC‘). IIEC points out the NARUC manual recognizes that utility Accounts 364-370 have a customer component and recognizes the use of the minimum distribution system (‘MDS‘) concept.

IIEC suggests the MDS concept recognizes that the cost of the distribution system is customer related as well as demand related. According to IIEC, the MDS concept recognizes that the cost of the distribution system includes a customer related component that is associated with the need to ‘cover the system.‘ IIEC posits that the distribution system is designed not only to meet customer demand, but to physically connect each customer's service***294** facilities to the system, regardless of the size of the customer. Therefore, according to IIEC, regardless of customer demand, there are some distribution facilities, of a minimum size, that must be used to connect the customer and his service to the system.

****144** IIEC notes ComEd has allocated all of Accounts 364-368 to the demand function and as a result, IIEC argues that ComEd's study may over-allocate distribution costs to the non-residential classes. Therefore, it is IIEC's position that the cost responsibility of non-residential customers could be overstated under ComEd's ECOSS. Therefore, IIEC recommends the Commission direct ComEd to incorporate a MDS concept for Accounts 364-368 in its next ECOSS. In the alternative, IIEC requests the Commission direct ComEd to make the results of such a study available to the parties in the next delivery service rate case.

Commission Analysis and Conclusion

IIEC and BOMA are advocates for use of the minimum distribution system in performing an embedded cost of service study. They argue that such an approach is consistent with cost causation principles and is consistent with the NARUC approach to cost of service studies. Among other things, they contend that the distribution system is designed not only to meet customer demand, but to physically connect each customer's service facilities to the system, regardless of the size of the customer.

ComEd and Staff oppose use of the MDS because such an approach does not accurately allocate costs to those who cause them to be incurred and they point out that the Commission has repeatedly rejected the MDS approach. They argue, in part, that the MDS approach is flawed because there is only a distant relationship between distribution costs and the number of customers. They also suggest IIEC and BOMA support the MDS approach because it would shift costs from the demand to the customer function and thereby benefit large customers at the expense of smaller customers.

Based on the record in the instant case, the Commission rejects the minimum distribution or zero-intercept approach recommended by IIEC and BOMA for purposes of allocating distribution costs between the customer and demand functions. In the Commission's view, ComEd's method is consistent with the fact that distribution systems are designed primarily to serve electric demand, and the Commission believes that attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic. Furthermore, this conclusion is consistent with decisions in Dockets 99-0121 and 00-0802.

While the Commission is willing to consider the merits of the MDS approach in future rate proceedings, the Commission declines to adopt the suggestion that ComEd be required to present a COSS in its next rate case incorporating the MDS approach. In the Commission's view, it would be unreasonable to require ComEd to perform a COSS that incorporates a method the Company does not endorse and that the Commission has repeatedly rejected.

3. MARGINAL COST OF SERVICE ISSUES/ CONSIDERATIONS

ComEd

ComEd reserved its right to propose the use of a marginal cost of service study in future proceedings.

Weighting Factors

ComEd

****145** ComEd posits that while BOMA claims that certain weighting factors should be very similar for different non-residential delivery service customer classes, BOMA fails to offer any explanation for that claim.*See* McClanahan Dir., BOMA Ex. 2.0, 14:307-23; McClanahan Reb., BOMA Ex. 4.0, 9:198-214. In contrast, ComEd argues that it did explain the development of the weighting factors used to derive certain allocators employed in its ECOSS. Heintz Reb., ComEd Ex. 25.0, 9:182-92. According to ComEd, its weighting factors ***295** were not arbitrary. For instance, ComEd notes that pursuant to the filing requirements under Part 285 of the Commission's Rules (83 Ill. Adm. Code 285), it submitted work papers showing the development of these weighting factors. In addition, ComEd states that it provided spreadsheet versions of the work papers in ComEd's response to a data request from the Attorney General (AG 4.03).(*Id.*) ComEd further notes that it also provided explanations of the development of specific weighting factors in responses to data requests from Staff for Services (PL 3.32), Standard Meter (PL 3.33), Meter Reading (PL 3.34), Customer Account (PL 3.35), and Customer Information (PL 3.36).(*Id.*)

BOMA

BOMA states that another flaw in ComEd's embedded cost of service is the weighting factors that ComEd used to allocate certain types of costs to ComEd's proposed customer classes throughout ComEd's cost of service study. (BOMA Ex. 2.0, pg. 14, ll. 309- 314). BOMA witness McClanahan testified that the weighting factors used to allocate certain types of costs such as ComEd's metering services and billing and accounting expenses should not vary significantly across customer classes because these costs should be essentially the same on a per customer basis. (BOMA Exhibit 4.0, pg. 9, ll. 203-209). According to BOMA, BOMA Exhibit 2.5 shows that the weighting factors used by ComEd to allocate metering services and billing and accounting expenses varied widely among ComEd's proposed delivery services customer classes. For example, BOMA argues that BOMA Exhibit 2.5 demonstrates ComEd's Billing and Accounting weighting factor for ComEd's proposed Very Large Load class of 147.556 was approximately 60 times greater than the Billing and Accounting weighting factor for the Medium Load class of 2.427. (BOMA Ex. 2.5). According to BOMA, ComEd offered no explanation in testimony for the substantial difference in weighting factors used to allocate certain costs among ComEd's proposed customer classes in ComEd's embedded cost of service study. (BOMA Ex. 2.0, pg. 14, ll. 315-323). BOMA urges the Commission to order ComEd to address the problem of appropriate weighting factors in the cost of service study to be used in ComEd's next delivery services rate case.

Commission Analysis and Conclusion

BOMA believes that the weighting factors used to allocate certain types of costs, such as ComEd's metering services and billing and accounting expenses, should not vary significantly across customer classes because these costs should be essentially the same on a per customer basis. BOMA states that the weighting factors used by ComEd to allocate metering services and billing and accounting expenses varied widely among ComEd's proposed delivery services customer classes. BOMA therefore concludes that ComEd's cost of service study is flawed. ComEd claims it fully explained how its proposed weighting factors were developed and, essentially, that there is no reason to believe that the types of costs identified by BOMA are uniform across the various customer classes.

****146** BOMA is correct that the weighting factors identified on BOMA Exhibit 2.5 are widely different among the customer classes. However, ComEd is also correct that BOMA failed to provide a cogent explanation why one should expect the weighting factors to be similar across customer classes. Additionally, even if the Commission were inclined to accept BOMA's premise that the weighting factors should be similar across customer classes, which it is not given the lack of rationale in the record, BOMA failed to provide alternative weighting factors.

As for ComEd's proposed weighting factors, the documents accompanying ComEd's filing demonstrate how the weighting factors were calculated. Unfortunately, ComEd did not explain why one should expect the weighting factors to vary widely across customer classes. In the Commission's view, contrary to ComEd's suggestion, Mr. Heinz's rebuttal testimony does not explain how the weighting factors were developed. Nevertheless, the Commission finds ***296** that the only weighting factors in the record are those offered by ComEd and they are adopted.

The suggestion in BOMA's reply brief, however, that in its next rate case ComEd should be required to explain in testimony the basis for the weighting factors utilized in its cost of service study is reasonable. This recommendation is adopted and ComEd is directed to provide such direct testimony at the time it files its next rate case.

4. ALLOCATION OF DISTRIBUTION COSTS ComEd

[73-75] ComEd's ECOSS utilizes class NCP and CP demands to allocate distribution costs, which ComEd claims is consistent with previous Orders approving ComEd's prior ECOSSs. ComEd claims that its allocation methodology reflects the Commission's position that the interclass revenue allocation should be based on the principle of cost-causation and that distribution systems are designed primarily to serve demand.

According to ComEd, CUB/CCSAO proposes to depart from this long-standing methodology in favor of an allocation methodology that gives significant weight to the kWh consumption by class. ComEd states that CUB/CCSAO's ‘Peak and Average‘ (‘P&A‘) allocators would replace the NCP and CP allocators used in the ECOSS. ComEd says these P&A allocators give equal weighting to each class' share of kWh consumption (as provided in ComEd's filed ECOSS) with each class' share of NCP or CP, as the case may be.

ComEd contends that CUB/CCSAO's P&A method is arbitrary and results driven. ComEd asserts that CUB/CCSAO's desired result is to reduce the interclass allocation to the residential class produced by the ECOSS. In ComEd's view, CUB/CCSAO seek to shift costs away from the residential class and on to non-residential customers. By proposing its P&A allocation methodology, ComEd says CUB/ CCSAO is asking the Commission to abandon its long-standing reliance on the NCP and CP methodology in favor of a methodology that has no cost basis whatsoever.

ComEd states that this issue is indicative of the ‘tug of war‘ between various customer groups, in this case, that seek to shift costs to other customer classes. According to ComEd, while IIEC's minimum distribution system proposal attempts to shift costs to the residential class, CUB/CCSAO's P&A proposal attempts to do the opposite. ComEd contends that for this reason, it is imperative that the Commission adhere to established cost-causation principles and reject arbitrary methods of allocating costs.

****147** ComEd's claims its proposed ECOSS carefully reflects the Commission's decisions over recent delivery service rate cases. ComEd argues that Staff recognizes this fact and points out that Staff has proposed no changes to the ECOSS. ComEd argues that CUB/CCSAO's unsupported and arbitrary allocation methodology should be rejected.

CUB/CCSAO

CUB/CCSAO indicate that ComEd's ECOSS allocates distribution demand costs for distribution substations, distribution lines and line transformers among rate classes solely on the basis of non-coincident peak (‘NCP‘) demand. They argue, however, that because ComEd is a ‘wires only‘ distribution utility, investments in the distribution system are justified by revenue from both peak and annual usage, and distribution demand costs are fixed, the Commission should adopt an alternative approach that takes into account both peak and average demand.

CUB/CCSAO argues that from a policy perspective, a distribution only electric utility is structurally very similar to the natural gas utilities that are regulated by the ICC. CUB/ CCSAO states that a gas distribution utility purchases capacity from pipelines and independent projects and delivers gas to customers by using distribution mains. In a restructured electricity market, CUB/CCSAO argues that the electric utility distribution company will purchase power or its customers will purchase power ***297** through marketers; the electric utility will provide distribution service. In CUB/CCSAO's view, a fair approach to electric distribution cost of service would therefore be consistent with a fair approach to natural gas distribution cost of service; the Commission should set fair and equitable class revenue requirements by reflecting annual usage in the cost of service distribution demand allocators.

CUB/CCSAO concludes that ComEd's ECOSS should allocate demand-related costs on the same basis as LDCs do - based on average annual usage as well as peak demand.

CUB/CCSAO also contends there is an economic justification for allocating ComEd's distribution demand costs partly on average utilization of distribution facilities. In particular, CUB/CCSAO asserts ComEd's distribution system would not be built if the utility's investment in the system could not be recovered through revenue from annual as well as peak usage. They claim revenues from kilowatt-hour charges, which reflect average rather than peak usage, represent approximately one-third of ComEd's proposed revenue requirement. CUB/ CCSAO believes this is a significant share of the revenue requirement, and is comparable to the roughly 42 percent of ComEd's revenue requirement attributable to revenue from demand (kilowatt) charges. Without the revenue from both annual and peak usage, CUB/ CCSAO argues there would be no economic justification for ComEd's distribution substations, distribution lines and line transformers. CUB/CCSAO says the demand allocators used in ComEd's ECOSS fail to reflect this straightforward principle.

****148** CUB/CCSAO asserts that allocating distribution demand costs, which are fixed, on the basis of peak demand is inconsistent with ComEd's proposed allocation of the Supply Administration Charge (‘SAC‘). CUB/ CCSAO argues that although supply administration charges do not vary based on energy usage, ComEd proposes to allocate the SAC among customer classes based on kilowatt-hours - that is, average demand.

CUB/CCSAO posits that while ComEd and IIEC criticize as arbitrary CUB/CCSAO's equal weighting of peak and average demand, these criticisms completely ignore the explanation of the basis for equal weighting. CUB/ CCSAO notes that the calculated system load factor on a coincident peak and non-coincident peak basis is 51.3% and 47.4%, respectively, but, according to CUB/CCSAO, there were limitations in the load research used in those calculations. It is CUB/CCSAO's position that in the exercise of its discretion, the Commission may assign an unequal weighting to demand and annual sales.

CUB/CCSAO asserts that the distribution demand allocators used in ComEd's ECOSS should be adjusted to take into account class annual utilization of distribution facilities. They say this can be accomplished by assigning relative weight to both peak and average demand in allocating distribution demand costs.

CUB-City-CCSAO

According to CCC, ComEd's proposed class revenue allocation is based solely on the ECOSS, and does not consider rate impacts on particular customer classes. As a matter of fairness and equity, they claim the allocation of ComEd's revenue requirement among the rate classes should take into account relative class utilization of the distribution system.

CCC assert that rate moderation is a well-established rate design principle and that rate mitigation should be applied, not just to ComEd's procurement of power, but to its distribution function as well. CCC contends that to mitigate the impact on residential customers of ComEd's proposed $135.7 million increase in residential distribution rates, the Commission should consider criteria other than just cost of service, including average class utilization of distribution facilities and class risk differentials. In CCC's view, adopting a reduced rate increase of $45.2 million - $90.5 million less than ComEd's proposed increase - based on Mr. Ruback's adjusted P&A cost of service study would appropriately reflect these key non-cost criteria.

CCC avers that ComEd's insistence that inter-class revenue requirements be based ***298** entirely on cost ignores the limitations of cost of service studies. CCC argues that developing distribution demand allocators in cost of service studies is not an exact science, and accordingly requires some judgment. CCC asserts that numerous methodologies with the potential for widely varying results can reasonably be used in conducting cost of service studies. For example, CCC states that measurements of demand used in developing allocation factors are the product of load research, which, in their view, is not unassailable.

****149** CCC contends that ComEd's ‘slavish‘ adherence to the ECOSS in setting class revenue requirements is inappropriate given that this proceeding concerns retail distribution rates for a monopoly service. They assert that basing revenue requirements on the system average rate of return is proper in determining wholesale and jurisdictional revenue requirements, which do not implicate rate impacts on particular classes, but not in establishing inter-class retail distribution revenue requirements. CCC claims that doing otherwise would strip the Commission of its discretion to mitigate customer impacts in setting class revenue requirements.

CCC recommends that the Commission ensure that the allocation of ComEd's revenue requirement among customer classes is fair and avoids rate shock. To do this, CCC proposes that class revenue requirements be based on criteria other than just cost, including relative class utilization of the distribution system.

IIEC

IIEC states that CUB/CCSAO witness Ruback recommended that 50% of the cost of the distribution system should be allocated on the basis of electric energy (kWh) used by customers.

In response IIEC points out ComEd no longer owns electric production facilities. Thus, by definition, it reasons production costs are no longer reflected in ComEd's ECOSS. As a result, it would be erroneous to conclude, as the Mr. Ruback did, that the elimination of production costs from the ComEd ECOSS necessitates a change in the method for allocating distribution costs. Mr. Ruback also suggested that it would be ‘fair‘ to recognize annual consumption of energy in the allocation of non-customer related (*i.e.*, demand related) distribution costs. IIEC states that these proposals should be rejected for several reasons.

First, IIEC argues that removal of production costs from the ECOSS does not mean that the method for allocation of other costs, such as distribution costs, needs to be altered or modified. According to IIEC, removal of production costs does not change the fact that distribution costs are caused by, and a function of, the number of customers and their demands on the system. In other words, IIEC avers that there is no change in the cost causation of the distribution system when production costs are removed from consideration in the ECOSS just as the cost of operating a car is not changed when the radio is removed from the car.

Second, IIEC argues that fairness does not provide a basis for changing the allocation of 100% of distribution costs on the basis of demand and number of customers to allocating 50% of those costs on the basis of kWh used. IIEC states that while fairness and equity require costs to be allocated to cost causers, it does not require that costs be allocated in accordance with any individual's subjective definition of fairness.

IIEC states that Mr. Ruback attempts to illustrate the unfairness of failing to allocate distribution costs on the basis of kWh used by providing an example of two customers with the same demands, but one of which uses three times the kWh of the other. IIEC notes that Mr. Ruback concluded that a demand-based allocation of distribution costs to these customers would be unfair because both customers would pay the same. However, IIEC argues that the fact that one customer may make fuller use of facilities that are designed and installed to serve the same level of demand for electricity does not make it fair to allocate more of the cost of that demand related investment to one customer than another. According to IIEC, the only fair approach would be to allocate the same amount of cost to each customer since the utility incurs ***299** no greater cost to serve the first customer than the second.

****150** IIEC argues that to allocate distribution costs that are essentially demand or customer related on the basis of kWh consumed is equivalent to charging one customer more than another customer for the same camera simply because the second customer intends to take more pictures. According to IIEC, Mr. Ruback's proposal is arbitrary and has no factual or logical support in the record other than the witness' subjective opinion of what is fair. IIEC witness Chalfant, who has testified in twenty cases in Illinois, has never seen Mr. Ruback's recommended approach adopted in an Illinois electric case. Also, Mr. Chalfant testified that such proposals are rarely made and when made, have usually been rejected. IIEC argues that such proposals should also be rejected in this case.*Commission Analysis and Conclusion*

ComEd's ECOSS uses non-coincident peak demands and coincident peak demands to allocate distribution costs, which ComEd claims is consistent with previous Commission orders. ComEd argues that the distribution system is built primarily to serve demand. IIEC supports ComEd's proposed allocation factors. CUB/ CCSAO, as well as the City, recommends that the Commission utilize peak and average (‘P&A‘) allocation factor for purposes of allocating distribution substation, distribution lines and line transformers among rate classes.

In this instance, ComEd cites previous delivery services rate orders where the Commission has found that distribution systems are designed primarily to serve demand. However, the conclusions cited by ComEd were made in the context of whether the Commission should consider whether a portion of the cost of distribution system was incurred simply to connect customers to the distribution system. In the Commission's view, the question here is whether the cost of the distribution system is related only and directly to peak demand or whether it is appropriate to allocate a portion of cost of the distribution system on the basis of average usage of the system. The Commission believes these issues are distinguishable and, contrary to ComEd's suggestion, finds it is improper to place too much reliance on the rationale underlying previous decisions on a related but different issue.

CCC suggests that the Commission's decision in recent local distribution gas cases is more on point. In cases such as Ameren's recent natural gas rate case, Dockets 02-0798/ 03-0008/03-0009 (cons.), the Commission has adopted the average and peak (‘A&P‘) method for allocating investment in natural gas transmission and distribution. ComEd criticizes the CCC proposed allocation factor, alleging that it is arbitrary, is not cost-based, and is not consistent with the allocation factor previously approved by the Commission for allocating distribution costs. CCC argues that the primary reason for considering the P&A allocation factor is to mitigate the distribution rate increase that would otherwise be faced by residential customers. While the Commission concurs that rate continuity and rate shock are legitimate concerns, it does not believe such considerations should influence which allocation factors are adopted in a cost of service study.

****151** The Commission observes that the record regarding the proper method for allocating distribution costs was better developed in Dockets 02-0798/03-0008/03-0009 (cons.) than here. Ultimately, however, the Commission rejects the CCC suggestion that rate mitigation concerns fully justify using the P&A allocation factor. While it is not entirely clear which allocation factor is superior for allocating electric distribution investment costs, the Commission will continue to use the non-coincident peak demand and coincident peak demand based allocation factors adopted in ComEd's last rate case. The Commission believes the record simply does not justify deviating from this practice.

However, because the Commission has previously adopted the A&P allocation factor for distribution costs in natural rate cases and due to similarities between the natural gas and electric distribution business, the Commission remains open to considering the merits of adopting the P&A allocation factor based upon ***300** a more thoroughly developed record in future electric distribution rate cases.

VII. REVENUE ALLOCATION

1. CLASS RISK DIFFERENTIALS/EQUAL RATES OF RETURN

ComEd

[76] ComEd explains that its proposed rate design assigns the revenue requirement to each customer class in a manner consistent with the established methodology proposed by ComEd in past cases.*Commonwealth Edison Co.*, ICC Docket 99-0117 (Order, Aug. 26, 1999); *Commonwealth Edison Co.*, ICC Docket 01-0423 (Order, Mar. 28, 2003). Specifically, ComEd proposes to assign the revenue requirement on an Equal Percentage of Embedded Cost (‘EPEC ‘) basis.*See,e.g.*, Crumrine Dir., ComEd Ex. 9.0 Corr., 43:937-44:944; *see also* ComEd Ex. 10.9. ComEd notes that this method should be adopted because it eliminates interclass subsidies, on an embedded cost basis, between rate classes.[FN22]

ComEd notes that CUB-CCSAO's proposal that only 97.5% of the residential class' costs be allocated to the residential class (*see* Ruback Dir., CCC Ex. 3.0, at 29:601-03) would depart from a benchmark allocation methodology in favor of one that shifts portions of the revenue requirement to the non-residential classes based on speculation rather than on a cost basis.*See,e.g.*, Heintz Reb., ComEd Ex. 25.0, 6:125-7:134; Crumrine Reb., ComEd Ex. 23.0, 37:794-99. ComEd points out that the 'basis' for this proposal is CCC's unsupported, and completely speculative conclusion, that the 'residential class is less risky.' Heintz Reb., ComEd Ex. 25.0 39:822-40:849. ComEd argues that this proposal simply is another attempt to improperly shift costs away from the residential class - costs that then must be recovered from other of customer classes.

ComEd notes that the record contains no evidence showing that the residential class is less risky to serve than other classes. ComEd claims that CCC provided no basis or logic for this conclusion, either. Rather, ComEd argues, the evidence demonstrates the opposite-that the residential class is at least as, if not more risky, in terms of ComEd's cash flow, than other classes. Crumrine Reb., ComEd Ex. 23.0, at 39:831-44. As an example, ComEd notes that the type of metering used for the residential class tends to focus cost recovery on volumetric rates rather than demand.*Id.* ComEd explains that this is problematic for cost recovery, as many factors beyond ComEd's control affect a customer's consumption decisions (including income, weather, and personal preferences, etc.).*Id.* On the other hand, ComEd further explains, for most other customer classes, revenue recovery is largely determined based on demand, which is generally less volatile.*Id.* ComEd also notes that the residential class tends to have greater turnover and a higher concentration of uncollectible accounts, both of which factors inhibit ComEd's ability to recover its costs from residential customers.*Id.*

****152** ComEd concludes that the Commission should reject CCC's arbitrary and unsupported methodology, and, instead, continue to strive for cost-based rates that are designed to achieve the elimination of interclass subsidies, as it has done in past cases.

CUB-CCSAO-City

CCC maintains that because the residential class is less risky to serve than other classes of service, ComEd's proposal to set its distribution inter-class revenue requirement based on equal class rates of return is unfair and inappropriate. CCC notes that the delivery service rates established in ComEd's previous two rate cases were not actually paid by residential customers because there were no alternative suppliers serving such customers, whereas the rates set in this proceeding will actually be paid by residential ratepayers. CCC adds that in this case, ComEd proposes to increase the residential class revenue requirement by $135,729, 355 - a 16 percent increase. Thus, CCC contends that in determining whether ComEd's rate proposals are just and reasonable, the Commission should consider carefully the impact of this proposed ***301** increase on the residential class. CCC notes that, as ComEd President Frank Clark acknowledged under cross-examination, the consensus of the Rates Working Group of the Post-2006 Initiative was that in restructuring rates to more accurately reflect the cost of providing delivery and customer services, the Commission should consider such traditional rate design principles as reasonableness, rate continuity and avoidance of rate shock. Mar. 21, 2006 Tr. at 190.

CCC witness Ruback testified that to mitigate the impact on residential customers of large increases in ComEd's delivery service rates, the Commission should consider non-cost criteria as well as the cost of service. CCC contends that disparities in the risk of serving particular rate classes is a key non-cost consideration in establishing class rates of return, as is relative class annual utilization of distribution facilities. CCC argues that the Commission should recognize class risk differentials even if it rejects Mr. Ruback's P&A method for allocating distribution demand costs.

Further, CCC argues, taking class risk differentials into account would be consistent with the well-established principle that the riskier a utility is, the higher the rate of return allowed by public utility commissions. Thus, CCC maintains that the riskier a particular class is to serve, the higher the Commission should set the class' target index rate of return; the target index rate of return for the residential class should therefore be lower than the system average of 1.00. To reflect the lower risk of serving the residential class, CCC recommends that the Commission set the residential class index rate of return at 97.5 percent of the system average.

In addition, CCC argues that ComEd's and IIEC's assertions that the residential class is riskier to serve do not warrant rejecting Mr. Ruback's recommendations. In particular, CCC claims that although both Mr. Crumrine and Mr. Chalfant averred that the residential class may be riskier to serve because residential customers pay bills based primarily on usage, which is affected by a number of factors beyond ComEd's control, this testimony fails to consider that ComEd's weather normalization of billing determinants blunts the effect of weather on ComEd's ability to recover the costs of service. Moreover, CCC states that unlike ComEd's and IIEC's testimony regarding class risk differentials, Mr. Ruback's contention that the residential class is less risky to serve is supported by empirical data showing that ComEd faces far greater revenue losses when a single large customer leaves the system than when a residential customer does.

****153** CCC argues that the Commission should reject Mr. Crumrine's assertion that cost recovery from the residential class is less reliable because uncollectible accounts tend to be concentrated in that class is entitled to no weight because ComEd recovers uncollectible expenses through base rates. Moreover, CCC notes, ComEd is one of several Illinois utilities that initiated an ongoing Commission proceeding, ICC Docket No. 05-0237, in which the utilities propose amending Part 280 of the Commission's rules - provisions that relate to recovery of uncollectible expenses - *inter alia*, to reduce the amount of bad debt.*Central Ill. Pub. Serv. Co., et al.* , ICC Docket No. 05-0237, Joint Verified Pet. at 1-2 (Apr. 4, 2005). Similarly, CCC continues, Mr. Crumrine's supposition that the residential class may be riskier because it tends to have greater turnover must fail because, as long as the fees necessary for turnover are reasonable, the risk to cost recovery should be negligible.

Finally, CCC points to the unrebutted testimony of Edward Bodmer to explain why the residential class is less risky to serve. Mr. Bodmer testified that residential revenues have ‘less variation related to overall economic activity (non-diversifiable risk) than revenues [ComEd] collects from other customer groups.‘ CCC Ex. 1.0 (2nd corrected) at 15, L. 435-37. Mr. Bodmer further testified that ComEd proposes increasing customer charges from $7.13 to $9.65 per month for single family customers, and from $2.94 per month to $9.65 per month for multi-family residences, Mar. 30, 2006 Tr. at 2308-09, and that such increases in fixed charges imply that a greater proportion of ComEd's revenues will not be subject to any variation at all based on energy usage.

****302** IIEC*

IIEC points out that ComEd proposes that for revenue allocation purposes, each customer class be assigned a share of the ComEd revenue requirement, such that the rate of return for each class would equal the system average rate of return. It also notes CUB/CCSAO witness Ruback proposed that a target rate of return for the residential class be set at 97.5% of the system average rate of return, because residential customers are allegedly ‘less risky to serve‘ than non-residential customers and have less ‘class risk‘. IIEC states that this recommendation is without credible foundation in the record and should be rejected for several reasons.

First, IIEC says Mr. Ruback failed to define the phrase ‘class risk‘ or explain why or how it is equivalent to the utility risks that are evaluated by regulatory commissions in establishing a utility's cost of capital. Nor did he indicate how such risks can be used in evaluating so-called class risk. Second, according to IIEC, Mr. Ruback provided no evidence for the record to rank or quantify any difference in risk among the various classes in this case. Third, according to IIEC, there is no evidence in the record of any link between a ranking or quantification of class risk and the 97.5% multiplier (or any other multiplier) Mr. Ruback developed. Fourth, IIEC argues the 97.5% multiplier is devoid of any factual basis in the record. Absent such a factual basis, IIEC says the Commission cannot and should not, adopt such a multiplier.

****154** Fifth, IIEC reasons there are facts in the record that suggest smaller customers may, in fact, be riskier to serve than larger customers. IIEC says ComEd rate design in this case contemplates that larger customers will pay their bill through a facilities distribution/demand charge and a customer charge. Thus, the revenue they furnish to ComEd will not be subject to changes in temperature, changes in seasons, or reductions in annual usage. On the other hand, bills for residential customers reflect a rate design which collects charges on the basis of the customer's usage. According to IIEC, usage can be dramatically affected by such things as weather. Therefore, IIEC avers, ComEd, on the basis of this rate design, may actually face less risk in serving larger customers rather than smaller customers. However, IIEC says it would be just as inappropriate to reflect this increased risk of serving smaller customers, in the allocation of revenue responsibility in this case, as it would be to reflect the alleged lower risk of serving smaller customers in such revenue allocation.

Therefore, IIEC recommends that the Commission reject CCC's recommendation to establish a target rate of return multiplier of 97.5% for the residential class.

Commission Analysis and Conclusion

Using its ECOSS, ComEd proposes to set the distribution interclass revenue requirement based upon equal class rates of return. CCC on the other hand, argues that because the residential class is less risky to serve than other classes, the interclass revenue requirement for that class should be indexed at 97.5 percent of the system average rate of return. IIEC opposes the CCC proposal and argues that smaller customers may actually be riskier to serve than larger customers.

Having reviewed the record, the Commission rejects the CCC proposal to set the distribution interclass revenue requirement on risk adjusted class rates of return. There is no indication that the Commission has ever adopted a risk adjusted class rate of return methodology. While this does not necessarily mean the Commission could not do so, the Commission finds that the record does not support deviating from past practices. There is no empirical evidence supporting CCC's 97.5 percent factor. In fact, it is not entirely clear to the Commission that if a class risk differential were applied to the residential class, such a factor should be less than 100 percent, as CCC proposes. As a result, the Commission finds it is appropriate to set the distribution interclass revenue requirement based upon equal class rates of return.

VIII. RATE DESIGN

1. CUSTOMER CLASS DELINEATIONS

***303** a.) Residential

ComEd

[77] ComEd notes that its existing customer classes for bundled electric service were designed prior to the 1997 Amendments to the Act, when ComEd was a vertically integrated utility that produced or purchased and sold all of the services necessary for customers to obtain bundled electric service. At that time, a customer's load shape and end-use characteristics generally were key cost drivers. However, ComEd points out that it no longer owns generation facilities. Therefore, according to ComEd, customer classes need to be designed based on its cost structure as a ‘wires‘ company, or an electricity distribution company.

****155** ComEd maintains that distribution costs incurred to serve residential customers are very similar and that four separate residential classes are no longer warranted. ComEd's ECOSS shows the following:

Unit Delivery Cost for Current Residential Sub-Classes

	Customer-Related Costs	Metering-Related Costs	Distribution

Current Residential Sub-Classes	($per Customer per Month)*	($per Customer per Month)*	Facilities-Related Costs ($/kWh)*
Single-Family Without Space Heat 8p	$7.74	$2.52	$0.0229
Multi-Family Without Space Heat 8p	$5.91	$2.52	$0.0220
Single-Family With Space Heat 8p	$8.02	$2.52	$0.0200
Multi-Family With Space Heat	$5.86	$2.52	$0.0199

Crumrine Dir., ComEd Ex. 9.0 Corr., 36:773-75. ComEd argues that the current distinction between single-family and multi-family residential rate classes should be eliminated because ComEd's ECOSS indicates that there is little cost difference in serving these two classes of customers. Accordingly, ComEd's proposed rate design consolidates the current four residential classes into one residential class.

ComEd maintains that there is no significant difference in the costs to serve multi-family versus single-family customers, or residential space heating versus non-space heating customers.

ComEd avers there is very little difference between single- and multi-family customer charges at proposed rates. According to ComEd, while the percentage increase for future electric bills may be higher for multi-family customers, the monthly dollar increase generally will be smaller. This is because multi-family residential customers generally have much lower usage than single-family dwellings because multi-family residences tend to be smaller, have fewer occupants, and fewer electric-powered fixtures and appliances. Multi-family residences also tend to remain unoccupied much longer and more often than single-family housing.

***304** ComEd also disputes the AG's assertion that meter installation and reading costs are lower for multi-family residences. ComEd indicates that multiple trips would be needed or multiple installers would be sent to a location in which a large meter bank would be installed in a multi-family residence. ComEd argues that, conversely, groups of meters are commonly installed in a single trip to a new development of single-family homes. ComEd also points out the fact that ComEd's service territory is a mix of urban and suburban areas that contain both single-and multi-family dwellings. According to ComEd, meters of single-family dwellings tend to be easily found and accessed due to their relatively uniform location on the outside of the residence. Meanwhile, multi-family meters tend to be inside the structure in locked utility/meter closets and the location of these closets is rarely uniform. Further, ComEd states that Multi-family dwellings are usually located in urban areas with significant traffic congestion.

****156** Similarly, ComEd challenges the AG's proposal for separate distribution rates for space heating and non-space heating residential customers. ComEd argues that there is only a miniscule difference in distribution costs between these customer classes of between 0.20 cents per kWh ($0.00199 per kWh) and 0.23 cents ($0.00229 per kWh). Crumrine Reb., ComEd Ex. 23.0, 20:421-429. ComEd indicates that this difference is generally within the ECOSS' margin of error. ComEd concludes that the very small difference between residential space heat and non-space heat distribution costs cited by the AG affirmed that distribution costs generally are not related to the use of electricity.

AG

The AG asserts that the Commission should reject ComEd's proposal to eliminate existing distinctions within its residential rate class, and, instead, retain the Company's existing rate distinctions between single-family and multi-family customers, and space-heating and non-heating customers. Specifically, the AG argues that: (1) ComEd's proposal results in extraordinarily high increases for low-use multi-family customers, even after applying the Staff proposed supply cost mitigation proposal; (2) there is no cost justification to eliminate the single/multi-family or heating/non-heating distinctions in residential rates; and (3) ComEd has not met its burden of demonstrating that consolidating all residential customers into a single rate class will result in just and reasonable rates.

The AG asserts that ComEd failed to perform a meaningful customer-impact analysis of its proposed rates, only looking at the effect on ComEd customers with usage between 500 and 1,000 KHW per month, and ignoring the hundreds of thousands of ComEd customers outside of that range. [FN23] Performing a broader analysis, AG witness, Scott J. Rubin, concluded that under the Company's rate design proposal, tens of thousands of customers who receive bundled service would see their bundled electric bills increase by more than 100%, and additionally tens of thousands of customers would face increases of more than 50%. Under ComEd's proposed revenue requirement and residential rate design, and under an unrealistically low wholesale energy price of $50/MWH, [FN24] Mr. Rubin found that 32.6% of residential customers would have their bills increase by 5% or less, 14.6% of ComEd's residential bills would increase by more than 25%, 3.9 million residential bills would increase by 30% or more (many bills increasing by 65-70%) and more than 560,000 bills would increase by more than 115%According to the AG, low-use multi-family customers would bear the brunt of the more severe increases.

AG witness Rubin testified that customers in multi-family buildings who use between 51 and 100 KWH per month would face increases of 55% to 70%. Customers in multi-family buildings using less than 50 KWH per month, about 10% of all bills to multi-family customers, would face increases of 115% to 125%. Multi-family customers who consume less than 250 KWH, representing 40% of all bills issued to multi-family customers, would face increases of 25% or more. Mr. Rubin further testified that applying ComEd's alternative assumed $60/ MWH price to energy, while, according to Mr. ***305** Rubin, still unrealistic, exacerbated the extreme impacts on low-use multi-family customers.

****157** Mr. Rubin proposed a rate design where more customers receive average or close-to-average increases so that fewer customers need to pay increases that are greatly above the average, resulting in the highest increases (assuming the Company's revenue requirement) in the 90-95% range, rather than the Company's highest increases in the 120-130% range. According to the AG, Mr. Rubin's proposed rate design lessens the impact of ComEd's proposed revenue requirement on low-use multifamily customers by about one-third. Further, the AG, citing the Final Order in ICC. Docket No. 91-0193 as affirmed by the appellate court *Central Illinois Public Service Co. v. Illinois Commerce Commission,* 243 Ill. App.3d 421, 601 N.E.2d 1356, 183 Ill. Dec. 112 (4th Dist. 1993), asserted that Mr. Rubin's analysis recognizes well-founded principles of gradualism and rate continuity and is fully consistent with the results of the Company's COSS.

The AG asserted that analyses of the costs of serving various customers do not support ComEd's proposed rate classes and reveal the distinctions between these proposed classes to be arbitrary, unsupported by costs to serve and contradictory.

The AG notes that ComEd witness Crumrine refers to the difference in the cost of serving single-family and multi-family customers, which differ by 36%, as ‘not significant,‘ and the difference between ComEd's proposed Small Load Delivery Class and Medium Load Delivery Class, which differ by 64%, to be significant enough to have separate rate classes. The AG argued that it is arbitrary to conclude that a difference in distribution cost of 36% does not justify retaining separate rates, while a difference in distribution cost of 64% does justify separate rates, and that there is a sufficiently large difference in distribution costs between single-family and multi-family residential customers to justify retaining existing separate rates.

The AG argues that the cost to read meters in single-family and multi-family buildings warrants retaining existing separate rates. AG witness Rubin testified that residential meter reading costs total $23,114,198, or approximately 23% of all residential meter-related costs. Citing a recent study by the Ascent Group, [FN25] Mr. Rubin posited that ComEd can read meters twice as efficiently in multi-family buildings as it does in single-family buildings. The AG argues that these differences should be reflected in rates to recognize the fact that the majority of ComEd's multi-family customers are in densely-populated areas, while many of its single-family customers are in suburban or rural areas. [FN26] Separate rates also reflect the added efficiency associated with reading meters in a multi-family building. Under the Company's proposed revenue requirement, Mr. Rubin's methodology developed a multi-family metering cost of $2.07 per customer per month, and a single-family metering cost of $2.75 per customer per month.

The AG opposes the Company's proposal to have the same distribution charge for all residential kilowatt-hours (‘KWh‘), arguing that the proposal contradicts ComEd's own COSS. Mr. Rubin estimated a difference in the distribution costs, recovered through the per KWh distribution charge, for space heating and non-heating customers of between 10%-15%. [FN27] At the same time, ComEd supports different rates between Small Load and Medium Load classes, where, according to the AG's estimate, there is only a 4.5% difference between the Small Load and Medium Load classes' distribution costs. Therefore, the AG argues, the greater difference in distribution costs between space-heating and non-heating customers clearly justifies separate rates for these two classes. Additionally, while ComEd argues that a single distribution charge would simplify tariff administration, the AG notes that eliminating existing distinctions in the distribution charge between heating and non-heating customers would be cost-inefficient, because the Company will already be retaining the heating classification in order to administer the Staff proposed supply mitigation proposal.

****158** The AG also argues that separate distribution rates are required for heating and non-heating customers, because the distribution charge ***306** is being recovered from customers on a per kilowatt hour (‘KWh‘) basis, and heating customers consume nearly three times as many KWhs as non-heating customers, without causing the distribution system to incur more costs. The AG argues that the cost to install and maintain the distribution system is not dramatically different for a heating or non-heating customer, and that cost does not vary significantly with the annual number of KWh the customer purchases. Thus, according to the AG, recovering the same cost per KWh from a customer who uses 5,000 KWh per year and one who uses 25,000 KWh per year would be patently unfair to the higher use customer, unless that customer's use was causing the system to incur more costs (as is the case with a summer-peaking, high use customer). In contrast, the AG argues that the Company's proposal, which has all residential customers paying the same distribution charge per KWh, would have the average heating customer pay nearly three times as much as the average non-heating customer for using the distribution system. Under ComEd's proposed revenue requirement, AG witness Rubin offered a distribution rate of 1.935 cents per KWH for heating customers and 2.214 cents per KWH for non-heating customers.

The AG argues that its proposal to retain existing rate distinctions is based on the actual cost of service, while ComEd's proposal to eliminate distinctions would result in certain groups of residential customers subsidizing others. According to the AG, while ComEd witness Landon claimed that, under Mr. Rubin's proposed rate design, ‘low-usage customers are presently being subsidized by other customers,‘ he offered no support for his contention. The AG argues that Mr. Rubin's proposed residential rates are fully consistent with the cost of service, and do not involve any cross-subsidies among the four sub-groups (single-family heating, multi-family heating, single-family non-heating, and multi-family non-heating) within the residential class. FN28 In contrast, ComEd's proposal to meld these groups into one would result in some groups of residential customers (primarily low-use multi-family customers) subsidizing other groups of residential customers (primarily high-use single-family customers).

Based upon the arguments put forth and evidence offered by the AG in the instant proceeding, the AG contends that ComEd fails to meet its burden of proving that elimination of the residential rate class distinctions is just and reasonable.

According to the AG the Company offers many reasons to eliminate rate distinctions within the residential class, none of which are supported in the record or meet the Company's burden of proof to establish just and reasonable rates. The AG notes that the Company cited to: 1) the extra complexity in maintaining separate rate classes; 2) higher vacancy rates in multi-family dwellings than in single-family dwellings; 3) higher uncollectible expense per multi-family customer than per single-family customer; and 4) industry practices. Mr. Rubin argued that none of these statements justify eliminating rate distinctions in the residential class. In response to ComEd's support for consolidating residential rate classes, the AG offers the following arguments. First, the AG contends that ComEd did not show that maintaining the residential rate distinctions would create one dollar of additional costs, or that eliminating them would save the Company any money, due to simplifying tariff administration or otherwise. Second, the AG argues that occupancy rates have no effect on metering and billing cost allocation, and actual billing units already reflect any vacancies that occurred during the test year. Third, contrary to ComEd witness Crumrine's suggestion that the uncollectible expense per multi-family customer is higher than it is per single-family customer, the AG avers the Company's own COSS shows that uncollectible expense per customer is *lower* for multi-family customers than it is for single-family customers. Finally, while ComEd witness Crumrine referred to an informal industry study to suggest that most electric utilities do not have separate rates for multi-family customers, the AG witness Rubin testified that other utilities currently do have separate rates for multifamily residential customers. FN29 Mr. Rubin noted as well that a utility lacking a multifamily rate ***307** does not necessarily mean that it rejected such a rate; rather it could mean that there is no need for such a rate because, according to Mr. Rubin, most multi-family buildings are master-metered.

****159** In total, the AG argues that the rates proposed by Mr. Rubin are superior to the Company's proposal because they are fully consistent with the Company's own COSS and they are consistent with principles of gradualism and rate continuity. According to the AG, it would be unreasonable to implement ComEd's rates as filed because they fail to reflect real differences in the cost of serving different groups of residential customers and will result in extraordinarily high increases for low-use multi-family customers, even after applying the Staff proposed supply cost mitigation proposal. Finally, the AG argues that Mr. Rubin's proposed rate design should be applied to whatever revenue requirement is approved by the Commission using the ‘straight - scale back‘ approach, which reduces each of the charges Mr. Rubin proposes by an equal percentage. FN30

CUB-CCSAO-City

CCC argues that the Commission should reject ComEd's proposal to consolidate the single- and multi-family subclasses into one class because distribution costs are lower for multi-family customers than for single-family customers. CCC cited the testimony of Edward Bodmer in ComEd's last rate case (Docket 01-0423), who testified that the reason for the cost difference is that density affects the length or size (and cost) of distribution facilities installed to serve a particular area. CCC Ex. 4.01 at 72, L. 1413-15.

CCC also argues that ComEd's claim that the costs of serving single-family versus multi-family customers do not differ significantly is entitled to no weight because, as was the case in Docket No. 01-0423, ComEd's ECOSS does not classify distribution costs according to population density.

In addition, CCC cites AG witness Rubin's testimony that ComEd's own cost of service study shows a 36 percent difference in the cost of serving single-family versus multi-family customers. AG Ex. 1.0 at 15, L. 313-15. Although Mr. Crumrine has characterized this cost difference as insufficient to warrant maintaining separate classes for multi-family and single-family customers, CCC asserts that he did not identify how large of a cost difference is required in his view before customers should be moved to separate classes. Additionally, CCC contends that ComEd's rate design proposal should be rejected because it would have an enormous impact on low-use, multi-family customers. Specifically, CCC cites Mr. Rubin's bill impact analysis showing that depending on the energy prices resulting from the auction ComEd plans to use to procure electricity in the post-transition era, bills for customers in multi-family buildings who use between 51 and 100 Kwh per month would increase by 55 to 70 percent, while bills for multi-family building customers who use less than 50 KWH per month would increase by 115 to 125 percent.

Commission Analysis and Conclusion

ComEd proposes to merge the four existing residential rate classes into a single residential delivery rate class. ComEd alleges that the costs of providing delivery services to the existing classes are so similar that separate classes are not justified. According to ComEd, this logic applies to the existing differential between single and multi family residences as well as space heating and non-space heating residences. Among other things, ComEd argues that because the delivery charges involve a relatively small amount, complaints about percentage increases in rates are not significant.

****160** The AG's recommends that ComEd's residential rates retain the existing distinction in customer charge and meter charge between customers in single-family and multi-family buildings. The AG also proposes that ComEd retain separate distribution rates for heating and non-heating customers. Finally, the AG recommends that Staff's mitigation proposal, from the Company's procurement docket be applied to recognize differences between residential customers in single-family and multi-family buildings. ***308** The AG argues that ComEd's proposal would have a significant adverse impact on a large number of residential customers.

CCC also objects to ComEd's proposal to merge the four existing residential rate classes into one.

The Commission has reviewed the record and rejects ComEd's proposal to consolidate the four existing residential rate classes into a single residential delivery class. The primary reason for this conclusion is the relatively large rate increases faced by some customers. The Commission also concludes that ComEd's ECOSS shows that in some instances the cost of providing service to different types of residential customers is not as close as the Company suggests.

The Commission is concerned with ComEd's apparent lack of concern about the impact of its proposed electric rates on customers. The Commission is not receptive to ComEd's suggestion that tariff administration is more important than the dollar or percentage rate increases faced by customers. The record demonstrates that the rate consolidation itself would produce large rate increases for certain customers. Additionally, while acknowledging that it is somewhat of a judgment call, the Commission believes that in several instances there is a sufficient cost basis for maintaining separate residential rate classes.

The Commission also believes that the AG has raised a valid concern in that creating a single residential distribution usage charge may result in many residential customers overpaying and other residential customers underpaying for distribution services. While ComEd may be indifferent to this result, the Commission is not and customers certainly are not. ComEd's analysis shows that many customers would not face significant rate increases in the event the existing residential rate classes were merged, however, and somewhat surprisingly the record shows that certain high use, as well as certain low use, residential customers face significant increases. The peculiar distribution of various types of residential customers that face significant increases under ComEd's proposal is troubling to the Commission.

The Commission adopts the AG's recommendation that ComEd use its ECOSS to develop separate customer charges for single-family and multi-family residential customers, without regard to heating characteristics. ComEd's ECOSS shows a meaningful difference in customer-related costs between single and multi-family residences. While ComEd may not consider approximately $2 per month significant, the Commission finds that it justifies separate rate classes.

****161** The Commission gives little weight to the AG's or ComEd's subjective arguments regarding the cost of installing and reading residential meters. Nevertheless, the Commission does not find that the record supports AG's assertion that meter related costs are significantly different for single versus multi-family residential customers. Therefore, the Commission directs ComEd to develop a single residential metering charge using its ECOSS.

The record does not support ComEd's assertion that a single distribution facilities charge is appropriate for all residential customers. The Commission believes the distribution facilities cost differences, as shown in the results of ComEd's ECOSS, warrant different rates for space heating and non-spacing heating residential customers. Because the distribution facilities charge for residential customers is a usage charge and electric space heat customers on an annual basis typically use more kilowatt-hours than non-space heat customers, a separate distribution facilities charge for the two types of customers is warranted. Combining these two rate classes for purposes of calculating this charge would almost certainly result in one group subsidizing the other with the only apparent benefit being streamlined tariff administration for ComEd. ComEd is directed to use its COSS to develop separate distribution facilities charges for space heating and non-space heating residential customers.

Using the revenue requirement approved in this Order and its ECOSS, ComEd is directed to develop residential rates that comply with these findings. Finally, the Commission rejects the AG's proposal to modify the rate mitigation proposal adopted in Docket 05-0159.While ***309** utility rate increases are unpleasant, the Commission concludes that the rate design adopted herein along with the rate mitigation plan adopted in Docket 05-0159 will sufficiently mitigate the adverse rate impacts for most residential customers.

2. NON-RESIDENTIAL

a.) Railroad Class

ComEd

[78, 79] ComEd's initial filing maintained a separate delivery class for railroad traction power customers. In response to concerns raised by the CTA regarding standard service, ComEd modified its proposal to eliminate the railroad class and provide one-line service as standard to each railroad traction power substation.

CTA and Metra

The Railroad Class is comprised of two members, the Chicago Transit Authority (‘CTA‘) and the Northeast Illinois Regional Commuter Rail Corporation, d/b/a Metra (‘Metra‘). CTA and Metra assert that they are critical components of the public transportation system serving Chicago and the six county Chicago metropolitan region.

CTA is one of the largest, if not the largest, customer of ComEd. CTA is an Illinois municipal corporation and operates the second largest public transportation system in the United States. According to CTA, total annual ridership on the CTA is 450 million rides by bus and rail, and has grown in recent years as road congestion has increased and gas prices have risen.

****162** Metra also is a municipal corporation, and is a Service Board of the Regional Transportation Authority. Metra provides, either directly or through purchase of service agreements with other railroads, intercity train service over a 495-mile system that serves 230 stations in the counties of Cook, DuPage, Lake, Will, McHenry, and Kane. Metra provides intercity transportation to approximately 300,000 daily weekday rides, and 83 million annual rides. Metra operates the second largest commuter rail system in the country.

Both CTA and Metra have written contracts with ComEd that govern their relationships. The relationship between the CTA and ComEd is governed by a written agreement that has been in effect since 1958 that has been amended several times with the most recent substantive revision in 1998. The relationship between Metra and ComEd is governed by a 1986 contract in which various rate provisions have been amended over time.

Both CTA and Metra currently purchase electricity from ComEd under bundled rates. The CTA currently is billed for bundled service as if it were a Rate 6L customer. Metra states that it purchases approximately 65 percent of its electricity for traction power for its electric train service. That electricity is purchased under its contract rate. The remainder of its electricity is purchased under Rate 6, primarily for the standby yards for Metra's diesel train service.

If the tariffs filed by ComEd are approved in this docket, CTA and Metra note that they would be required to take delivery service under the Railroad Class rate. CTA and Metra note that in surrebuttal testimony, ComEd proposed eliminating the Railroad Class entirely as a ‘compromise‘ to CTA's and Metra's concerns. Neither CTA nor Metra support the elimination of the Railroad Class since, according to CTA and Metra, ComEd's surrebuttal proposal would lead to the two entities paying even more to ComEd. Both CTA and Metra explain that if they are required to take service under the Railroad Class rate as proposed, their costs for power and energy would increase substantially. CTA and Metra argue that such an increase in a major cost raises the distinct possibility that either or both the CTA and Metra would be required to increase its fares. CTA and Metra posit that any resulting fare increase for mass transit ultimately could cause reduced ridership and an increase in the use of private vehicles. CTA and Metra state that the unintended consequence of the Commission's approval of ComEd's request would be to increase energy consumption and to contribute to poor air quality in the greater Chicago area. CTA further testified ***310** that the ComEd Railroad Class rate is not supported by the CTA's usage patterns, is discriminatory against the CTA relative to other large customers and is poor public policy. CTA and Metra propose that the appropriate rate for the Railroad Class is a price no higher than the price charged to the 10 MW and above class customers.

CTA's witnesses testified that currently ComEd's delivery services rate for the Railroad Class is 85 per cent higher than the rate for the 10 MW and above class. If ComEd's original proposal in this docket is adopted, CTA and Metra estimate that the Railroad Class rate would increase by another 26 per cent, further widening the rate disparity. CTA witnesses Mr. Anosike and Mr. Zika gave several reasons why the Railroad Class rate should be priced no higher than the10 MW and above price. They were:

****163** • The CTA uses more than 10 MW. The CTA's peak load is slightly below 120 MW and occurs in the winter. The CTA's summer peak is around 90 MW. CTA's peak occurs at a different time of day than ComEd's peak and the CTA summer peak is lower.

• There is no evidence in the ComEd cost of service study to support disparate treatment between the Railroad Class and the 10 MW and above class. Under ComEd's own methodology, the CTA is allocated costs on the basis of demand in precisely the same way that costs are allocated for the other 10 MW and above customers.

• The CTA's use of the ComEd distribution system is not materially different than the way other customers with large load use ComEd's distribution equipment, so there is no justification for a different rate classification for the Railroad Class.

• The CTA has invested hundreds of millions of dollars in developing its own distribution system that not only moves power and energy through the CTA system but also aids the ComEd system by providing localized looped service for ComEd's own reliability.

Metra has made similar arguments based on the evidence and testimony.

According to CTA, the existing Railroad Class delivery services tariff has prevented the CTA from obtaining any economic alternative to ComEd's bundled service. CTA contends that had the Railroad Class's price been set properly, it could have obtained more economic power and energy for its traction power service.

CTA also asserts that the Railroad Class rate is inappropriate because the Railroad Class is more negatively impacted by ComEd's change in its costing methodology using the non-coincident peak to allocate more costs. While most customer classes see no material difference in the change, CTA avers that the Railroad Class is allocated 30 per cent more of ComEd's costs using the non-coincident peak rather than the coincident peak method. For the Railroad Class, CTA argues that this change alone adds nine per cent to the class's delivery system costs.

***311** CTA and Metra emphasize that as public transit agencies, they can obtain operating funds from the fare box or from taxes. The bottom line is that any increase in operating costs must ultimately come from Chicago and the Chicago metropolitan area residents and commuters. Any increase in fares may lead to a decrease in ridership. Since mass transit is more energy efficient than private transportation, a fare increase is detrimental to the nation's overall energy policy. In response to the questions raised by Commissioners Lieberman and Ford, both the CTA and Metra suggested that inappropriate rate design, such as that advocated by ComEd, will adversely affect conservation of energy and adversely affect not only the Chicago economy but also have detrimental environmental effects, contrary to the request by the ICC Staff for the Commission to address global warming issues.

The CTA and Metra propose that these serious adverse effects can be mitigated by rejecting ComEd's rate design for the Railroad Class. Instead, CTA and Metra propose that the rate for distribution services for the Railroad Class should be set at a price no higher than the 10 MW and above class.

****164** CTA and Metra note that ComEd made an alternative proposal concerning the issues raised by CTA and Metra in the surrebuttal testimony of Mssrs. Alongi and McInerney (ComEd Ex. 41.0). Because the new proposal was made in ComEd's surrebuttal testimony, neither CTA nor Metra had an opportunity to provide testimony concerning the impact of the proposal. In essence, CTA and Metra assert that ComEd proposed eliminating the Railroad Class, making massive unilateral changes to the CTA and Metra contracts and eliminating consolidated billing so that each substation would be billed separately with demand being measured separately. CTA and Metra note that the proposed changes would prevent them from qualifying for service for 10 MW and above class. Further, CTA and Metra note that, under ComEd's proposal, the MKD, discussed later in this Order, would be calculated on a substation by substation basis, increasing the MKD's charged to the two entities. CTA and Metra oppose the last minute proposal to eliminate the Railroad Class because of all the adverse impacts and higher costs it would impose on them.

Commission Analysis and Conclusion

ComEd originally proposed to maintain a separate class for its two railroad traction power customers, CTA and Metra, and to provide bundled service for that railroad class under proposed Rate BES-RR. In rebuttal, ComEd modified its initial proposal, allegedly to accommodate certain concerns raised by the CTA. In the CTA's direct testimony, it expressed concern with respect to how ComEd's proposed Rate BES-RR limits CTA's access to multiple suppliers. In response, ComEd proposed to include revisions to Rate BES-H, Rate BES-RR, and Rate RDS in its compliance filing pursuant to the Commission's Order in this Docket. In surrebuttal testimony, ComEd has offered an alternative proposal in response to the testimony offered by the CTA, which would eliminate the proposed railroad class. ComEd has not identified all the specific tariff revisions that it believes would be necessary to implement this proposal.

The Commission understands that since 1998, the CTA has paid non-standard services and facilities charges for services based on the single electric service station standard consistent with Rate 6L and Rider 6. The CTA purchases service pursuant to an amendment to the contract negotiated with ComEd. Under the current arrangement, the CTA pays the energy charge listed in ComEd rate class 6L, the demand charges are consolidated under Rate GCB and the CTA also pays a reduced point of supply charge rather than the Railroad Class supply charge.

It is the CTA's position that the distribution service price applied to the Railroad Class should be no higher than the price charged to customers who take power and energy at 10 MW and above. The CTA contends it should be allocated costs on the basis of demand in precisely the same way that costs are allocated for other above 10 MW customers. In essence, the CTA is requesting that all of its demand be consolidated for purposes of computing its demand charges. The CTA says it is not requesting that the Commission eliminate the Railroad Class because of the unique aspects of the class, such as owning its own distribution system that enables consolidated billing for the various delivery points. In addition to its new proposed Rate BES-RR, it appears that Metra and the CTA also might be impacted by proposed changes in Rider GCB-7, Rider NS and ComEd's proposed change to the definition of Maximum kilowatts Delivered. It is far from clear to the Commission what the overall impact of ComEd's proposals on the railroad passengers will be. In fact, it appears that ComEd does not know what impact its proposals would have on the customers. ComEd apparently cannot identify the necessary changes to its contract with the CTA. Instead, ComEd suggests that it will make the conforming changes to the CTA contract after a final order is entered in this proceeding.

****165** Currently, ComEd has effective contracts with both the CTA and Metra. Due to the evolution of the electric market in Illinois, the existing CTA contract for bundled delivery and supply of electricity may not be workable after the ***312** end of the mandatory transition period. However, the Commission would have expected ComEd to negotiate a new contract for the delivery of power and energy with the CTA and present it to the Commission for approval.

As both Staff and ComEd assert, the current contracts for the CTA and Metra are no longer workable in the post-2006 era. The contracts refer to outdated terms and neither contract contains provisions for the post-2006 procurement. This docket deals with the distribution costs and not with procurement. At the time the contracts were created, ComEd owned the generation and there was no need to provide a transparent rate that separate distribution charges from generation related savings.

The Commission typically favors rates that are cost based; however, sometimes other considerations need to be addressed in setting utility rates. In this instance, there are several factors that lead the Commission to its decision regarding how the CTA and Metra will be charged. The most overriding fact is that ComEd currently has a contract with the CTA that provides for discounted distribution charges through Rider GCB. The Commission takes contractual obligations seriously and tries to leave them in tact whenever possible.

Also, the fact that the CTA and Metra are providers of mass public transportation raises an additional public interest concern. ComEd's proposal fails to account for the potential impact of increased utility rates for entities providing public transportation on the citizens of Illinois. The Commission is very concerned that any changes to the provisions of service providers of mass transit will not unduly burden the millions of passengers who depend on public transportation. This Commission also believes that it must consider the public policy implications of establishing delivery rates that encourage energy conservation and encourage electric usage during off-peak periods. While the Commission is not prepared to disregard cost of service, the Commission believes that important public policy considerations cannot be ignored.

In particular, the CTA currently pays the energy charge listed in ComEd's Rate 6L and the demand charges are consolidated under Rate GCB. The CTA also pays a reduced point of supply charge rather than the Railroad Class supply charge. Due to changes in the Act and the restructuring of the electric energy market in Illinois, Rate 6L, Rider 6, and Rider GCB will not be available after January 1, 2007.

In the Commission's view, the only reasonable solution is for ComEd to charge the CTA in a manner that is consistent with how it currently charges the CTA. In the event the CTA does not find an alternate supplier, ComEd will be allowed to assess appropriate supply charges that result from the procurement auction process approved in Docket 05-0159.The definition of MKD which affects the distribution facilities charges is addressed later in this Order.

****166** ComEd indicated that a 1998 contract amendment provided for a reduced point of supply charge to reflect the fact that the standard meter charge under the CTA contract would no longer be provided under Rider GCB. Also, the portion of the point of supply charge related to standard metering was removed.

Metra pays charges for electric supply and delivery under its existing contract with ComEd. Thus, Metra is in a different situation than the CTA. The Commission's review of the ComEd/Metra contract indicates that terms such as billing demand and kilowatt-hours supplied are defined in Article 6 of the contract while Article 7 lays out the ‘Alternating Current Charges.‘ Under the existing contract, Metra pays a negotiated demand charge, energy charge, point of supply charge and certain revenue tax charges. Unfortunately, in the post-2006 period, this contract is not totally enforceable.

Both the CTA and METRA argue that the contracts should control, but the parties failed to take into account the Integrated Distribution Company (‘IDC ‘) rules. 83 Ill. Admin. Code Section 452.230. Under this section of the Illinois Administrative Code, ‘[an] IDC shall not offer or provide any non-tariffed retail electric supply service or any non-tariffed transmission and distribution services‘. This section of the Act goes on to say ‘[a]n IDC shall not renew, ***313** extend, or renegotiate any existing contract for any retail electric supply service, unless the IDC is required by tariff to renew or extend or the IDC is contractually bound to renew, extend or renegotiate at the customer's option and the customer's has exercised this option.‘ 83 Ill. Admin. Code Section 452.230(b). This section of the Code is inconsistent with the positions of METRA and the CTA. However both contracts have provisions for changes or modifications by the Commission.

The Commission finds that rates set herein should place the CTA and Metra in a situation where they pay similar rates to those that are currently in effect. In addition, the Commission must consider the potential adverse impact of utility rate increases on entities that provide public transportation. The Commission desires to encourage the efficient use of energy and conservation of scarce resources. The conclusions reached in this portion of the Order are, in the Commission's view, important public policy issues and are in the public's best interest. Accordingly, the Commission finds that minimizing the change to existing contractual terms as necessitated by the post-2006 market changes, as well as avoiding rate shock to the railroad customers, is in the public's best interest.

Therefore, the Commission concludes that for the Railroad Class, these two customers should be allowed to consolidate their demand for purposes of calculating the applicable Distribution Facilities Charges under the delivery service rates that result from this proceeding. This provision would allow for consolidation of demand charges in a manner similar to that presently provided to them in Rider GCB. This demand consolidation provision would make these railroad customers eligible for the distribution facilities charges assessed to customers with demands in excess of 10 megawatts. The Commission observes that this arrangement follows the aggregation of demand under the existing CTA and Metra contracts. To the extent that the aggregation creates or otherwise represents a subsidy to the railroad class, the difference in cost should be recovered from the other non-residential classes.

****167** The Railroad Class, pursuant to existing contacts, unique aspects and public interest considerations are allowed to aggregate their demand to greater than 10 MW, are subject to the CPP-A auction rate if purchasing from ComEd. The Commission directs ComEd to conform Rate BES-RR subject to the above modifications along with the option to allow these customers to obtain alternative supply as set forth in ComEd's rebuttal testimony. The Commission is not ordering the termination of either contract as recommended by Staff. These contracts have a useful purpose for issues unrelated to rate design. Any changes to conform the contracts to this Order are subject to Commission approval.

b.) Very Large Load Customers

ComEd

[80] ComEd provided testimony supporting its conclusion that the underlying cost of service for its four largest demand-based non-residential customer classes was sufficiently close (differing by less than 3.5%) to justify combining these classes into the proposed Very Large Load Delivery Class. ComEd notes that this conclusion was consistent with the results of the ECOSS filed in ComEd's last delivery service case (ICC Docket 01-0423), which indicated very similar distribution costs among the classes that ComEd proposes to consolidate into the Very Large Load Class. Commonwealth Edison Co., ICC Docket 01-0423 (Order, April 1, 2002). ComEd also notes that the maintenance of the Over 10 MW class will result in a substantial subsidy to these customers.

ComEd contends that arguments to maintain an Over 10 MW class with an across-the-board increase were merely attempts to maintain a subsidy for the benefit of these high demand customers. In response to criticism by other parties regarding the need for a separate Over 10 MW class, ComEd reran its ECOSS to more closely examine the costs of serving large load customers. Initially, ComEd re-ran its ECOSS to separate the Over 10 MW customers from the other customers in the proposed Very ***314** Large Load Delivery Class. ComEd notes that this analysis demonstrated that the distribution facilities' costs for the Over 10 MW and the 1-10 MW class were virtually identical. ComEd subsequently again reran its ECOSS based on changes in ComEd's revenue requirement, with substantially the same result.

ComEd offers an alternative proposal, in the event that the Commission concludes that an Over 10 MW customer delivery class should be maintained. This proposal would phase-in the Distribution Facility Charge (‘DFC‘), moving this charge toward cost of service between this case and the next delivery service rate case that ComEd files. ComEd cautioned that without the approval of the 24-hour MKD as part of this proposal, customers with highly flexible loads that use dedicated distribution facilities primarily outside of the current Demand Peak Period will not only receive a subsidy in the form of a below cost DFC, but also will receive an intra-class subsidy. Therefore, ComEd suggested that if the Commission chose this alternative approach, that it approve the 24-hour MKD.

CTA and Metra

****168** The CTA and Metra have supported the request by the IIEC to maintain a class for customers with demands of 10 MW and above. The CTA and Metra also supported IIEC's methodology to determine the 10 MW and above rate for purposes of this Docket.

BOMA

BOMA proposes that ComEd retain all of its existing nonresidential customer classes and allocate any revenue requirement increase (or decrease) on an equal percentage, across-the-board basis to the existing customer classes. (BOMA Ex. 2.0, pg. 10, ll. 212-225; BOMA In. Br. pg. 11). BOMA witness McClanahan disagreed with ComEd's primary argument supporting its proposed rate consolidation that costs of providing delivery services to the classes ComEd proposes to combine must be very similar because the charges currently in effect and approved by the Commission for these classes of consumers are very similar. (BOMA Ex. 2.0, pp. 7-8, ll. 149-166; ComEd Ex. 9.0 Corr., pg. 38, ll. 811-815). BOMA witnesses Brookover and Childress testified that over 10 MW customers currently pay distribution facilities charges of $2.34 per kW, while customers with peak demands of 6-10 MW, 3-6 MW and 1-3 MW pay distribution facilities charges of $4.47, $4.63 and $4.45

per kW, respectively. (BOMA Ex. 1.0, pp. 13-14, ll. 280-289; Ill. C. C. No. 4, 3rd Revised Sheet No. 119-119.1)

BOMA notes also that ComEd has not segmented its ECOSS based on ComEd's existing nonresidential customer classes and therefore, according to BOMA, has not justified its proposed consolidation of its rate classes. (BOMA In. Br., pp. 9-10). BOMA witness McClanahan testified that the proper approach for ComEd would have been to conduct the cost of service study based on the current rate classes and then propose consolidation of rate classes if the costs indeed proved to be similar. (BOMA Ex. 2.0, pg. 9-10, ll. 205-208). Mr. McClanahan stated that this approach would have allowed the Commission to determine whether consolidation was justified. (BOMA Ex. 2.0, pg. 10, ll. 209-211).

BOMA contends that its approach of retaining all of ComEd's existing nonresidential customer classes and allocating any revenue requirement increase [or decrease] for nonresidential consumers on an equal percentage, across-the-board basis to the existing customer classes is the best way to handle the fact that, according to BOMA, ComEd's ECOSS did not justify ComEd's proposed consolidation of its delivery service rate classes. Further, BOMA maintains also its proposal is the best approach to avoid rate shock for over 10 MW consumers. (BOMA In. Br., pg. 11). However, in the event the Commission rejects this approach, BOMA proposes a separate rate class for over 10 MW consumers and phase in of any rate increase for these consumers regardless of whether the Commission adopts ComEd's 24-hour MKD proposal. (BOMA In. Br., pp. 11-12).

IIEC

***315** IIEC recommends retention of a separate class for 10 MW and over customers. IIEC notes that ComEd proposes to combine the four current non-residential rate classes into a single class, the Very Large Load Customer class, consisting of all customers 1 MW and over, other than those customers served at a high voltage level of 69 kV or higher. Customers served at 69kV or higher will be in a separate class.

****169** IIEC opposes the consolidation of the four current non-residential rate classes (*i.e.*, 1-3 MW customers, 3-6 MW customers, 6-10 MW customers and over 10 MW customers). IIEC recommends the over 10 MW class be retained as a separate class. IIEC points out that all parties who addressed this issue in their testimony agreed that ComEd's proposed combination of the non-residential customer classes should be rejected and a separate rate class of over 10 MW customers retained.

IIEC points out that ComEd's current delivery rate classes were approved by the Commission in ComEd's first delivery service rate case in Docket No. 99-0117.In that case the Commission concluded ComEd had appropriately defined its customer classes in accordance with the applicable provisions of the Act. The Commission concluded ComEd's size differentiated rate classes properly assigned costs in compliance with cost causation and were just and reasonable.

IIEC also points out that in Docket No. 01-0423, ComEd's last delivery service case, ComEd retained the rate classes approved in Docket No. 99-0117.IIEC states that the Commission concluded ComEd's rate design in that case was just and reasonable.

IIEC argues ComEd's proposal to combine the four non-residential rate classes into a single rate class would have significant impact on large customers, especially those with demands 10 MW and over. For example, 10 MW and over customers, depending on the voltage level at which they are served, will see increases in delivery service rates of 133% to 109% according to IIEC. Some customers, particularly those 10 MW and over customers served at high voltage could see increases as high as 160%.

IIEC notes ComEd's delivery service rates for above 10 MW customers are already much higher than those of any other Illinois utility and will be dramatically higher than those of other Illinois utilities if ComEd's rate increase is approved.

IIEC states that in ComEd's initial filing in this case, it offered two simple justifications for the combination of these rate classes. First, the charges currently in effect for the rate classes that were to be combined were very similar. Second, some of the granularity in ComEd's current rate structure was primarily the result of competitive transition charges (‘CTCs‘) and therefore, since CTCs would disappear after December 31, 2006, the current class separations were no longer needed.

IIEC says that neither of these factors provided sufficient justification for the Company's proposal. The first rationale is simply wrong according to IIEC. Current charges for 10 MW and over customers are approximately one-half of the charges applicable to the three smaller customer classes. Currently the facilities distribution charge, for 10 MW and over customers served at standard voltage, is $2.34 per kW. The same charge for the other three rate classes assuming service at standard voltages ranges from a low of $4.46 per kW to a high of $4.64 per kW. For 10 MW and over customers served at high voltage, the current facilities distribution charge is $1.04 per kW, while it ranges from $3.16 to $3.34 per kW for the other three rate classes, assuming service at high voltage.

****170** According to IIEC, the fact that charges to over 10 MW customers are significantly less than the charges to the other three subclasses would demonstrate that it is less costly to serve the 10 MW and over class. Thus, combination of the 10 MW and over class with other non-residential classes would not be justified.

IIEC presented a modified version of ComEd's cost of service study. The modified study demonstrated that for the main non-residential classes below 10 MW there were very similar demand costs and total costs per kW. However, there was a lower cost per kW for the over 10 MW class. In addition, IIEC points out the cost of service study ComEd presented in rebuttal testimony supports IIEC's conclusion ***316** that the cost of serving 10 MW and over customers are not similar to the cost of service the smaller non-residential classes. Studies presented by ComEd in its last delivery service case do not support ComEd's proposal to combine the four non-residential rate classes either. IIEC says those studies included 69 kV customers in each of the separate classes and the Commission rejected the use of the ComEd study in the last case for intraclass revenue allocations.

IIEC argues that ComEd's second rationale for combining the rate classes, namely, that granularity in the rate structure was primarily due to the application of CTCs, provides no valid basis for the combination of the existing non-residential classes. The 1997 Customer Choice and Rate Relief Law required calculation of individual CTCs for customers larger than 3 MW in ComEd's service territory. However, according to IIEC, this fact by itself does not necessarily require ComEd to establish a separate delivery service rate class at 3 MW and over, or at any other level.

IIEC points out ComEd established rate class separations at 1 MW, 3 MW, 6 MW and 10 MW in its initial delivery service case in Docket No. 99-0117, and continued its four class rate structure in its most recent delivery service rate case, Docket No. 01-0423. However, the 3 MW distinctions in the calculation of CTCs was no longer applicable at that time, since ComEd had begun to calculate individual CTCs for customers as small as 400 kW in demand. Thus, the existence of, and the need to calculate, CTCs could not have provided a basis for ComEd's original establishment or its later continuation of the four non-residential rate classes. Therefore, IIEC concludes elimination of the CTC, as of December 31, 2006, does not provide a valid basis for the combination of these classes as proposed by ComEd.

IIEC also argues ComEd's proposed Very Large Load Customer Class, consisting of all customers 1 MW and over, was not consistent with the power procurement segments that were approved at ComEd's request, in Commonwealth Edison Company Docket No. 05-0159.The break points for the power procurement segments were 400 kW and 3 MW, not at 1 MW as proposed by ComEd in this case.

In sum, IIEC says ComEd has failed to establish that the costs of serving the four existing non-residential classes are, in fact, similar, the record shows they are not, and ComEd has not offered any other legitimate reason for combining all four of the existing non-residential rate classes into a single rate class. Therefore, IIEC recommends a separate rate class for over 10 MW customers should be maintained.

**171 IIEC also recommends that in setting separate rates for standard voltage customers in the over 10 MW class, the Commission should start with the current (June 2006) rates and increase or decrease applicable charges in proportion to the overall revenue increase or decrease approved in this case. IIEC says under this approach, these customers, assuming ComEd's full rate relief would still see an increase of 25.7%, which is larger than the percentage increase that would be experienced by the other three non-residential classes, which range from 18% to 22%.

With regard to the 10 MW and over customers served at 69 kV and over (the high voltage class),

IIEC recommends the current net charge of $1.04 per kW, should be increased or decreased in proportion to the overall revenue increase or decrease approved in this case. Under this approach, and assuming the Company's full requested revenue increase, IIEC says these customers will also see a 25.7% increase. This increase is significantly higher, according to IIEC, than the increases to the remaining 69 kV customers, who would actually see decreases ranging from - 31% to a -35%.

Commission Analysis and Conclusion

It is ComEd's position that a separate over 10 MW customer class is unnecessary. In the event that the Commission concludes that an Over 10 MW customer delivery class should be maintained, ComEd has offered an alternative proposal. This proposal would phase-in the Distribution Facility Charge, moving this charge toward cost of service between this case and ***317** ComEd's next delivery service rate case. If the Commission chooses this approach, ComEd claims it is important that the 24-hour MKD be approved, as ComEd believes the two issues are linked.

It is ComEd's position that an across-the-board increase is not cost-based. If the Commission does wish to phase-in the increase for the Over 10 MW customers, ComEd proposes that the Over 10 MW customer class DFC be set at $3.86 per kW. This rate is one-half of the difference between the current Over 10 MW rate and the resulting rate based on ComEd's ECOSS filed in this case. ComEd also requests that the Commission formalize its policy of setting rates based on costs by requiring a full movement to cost-based rates for the Over 10 MW class in ComEd's next rate case.

IIEC opposes the consolidation of the four current non-residential rate classes. According to IIEC, ComEd's current rate class structure allowed the Commission to take into consideration voltage level differences as required under the Act. IIEC also claims the costs of serving the over 10 MW class were significantly lower than the cost of serving the other three non-residential classes.

In setting separate rates for standard voltage customers in the over 10 MW class, IIEC recommends that the Commission start with the current (June 2006) rates and increase or decrease applicable charges in proportion to the overall revenue increase or decrease approved in this case.

**172 BOMA prefers ComEd's alternative proposal that was presented in its surrebuttal testimony. However, it is BOMA's position that the best approach for the Commission is still the retention of all of ComEd's existing nonresidential customer classes. This would include the allocation of any revenue requirement increase (or decrease) on an equal percentage, across-the-board basis to the existing customer classes.

Both Metra and the CTA support the retention of the 10 MW and above class as a separate class within the Very Large Load class. Moreover, they argue that the rate set for the 10 MW and above class should be the ceiling for the rate charged to Metra and the CTA.

Currently, the four largest nonresidential rate classes are comprised of customers with demands over 1000 kilowatts or 1 megawatt. In its reply brief, ComEd complains that in making rate shock and rate stability arguments, the DOE and IIEC rely on percentage differences ‘rather than actual dollars and costs. ‘ (ComEd reply brief at 120) The Commission observes, however, that ComEd's argument is based solely on the dollar per kilowatt-hour delivery rate and not the dollar impact on customer bills.

The Commission finds that ComEd must maintain a separate rate class for those customers with demands greater than 10 mega- watts. This is due, largely, to the adverse rate impacts that would be faced by the largest customers. Further, the Commission notes that IIEC has made interesting arguments regarding the cost of serving the very large customers at issue here and the Commission is persuaded that the cost of serving such very large customers is potentially lower than serving significantly smaller customers. The Commission adopts IIEC's proposal for establishing rates for the over 10 megawatt rate class. In setting separate rates for standard voltage customers in the over 10 megawatt class, current charges will be increased in proportion to the overall revenue increase approved in this case.

Furthermore, at this time, the Commission declines to make any conclusions about how the over 10 megawatt rate class will be treated in future rate proceedings. Instead, in any future rate proceeding, consistent with requirements of the Act, the Commission will make decisions based upon the record.

c.) High Voltage Class Rates

ComEd

[81, 82] ComEd proposes the creation of a High Voltage Delivery Class because high voltage customers primarily use the distribution system operating at or above 69,000 volts to obtain electric power and energy. According to ComEd, these customers do not utilize a significant portion of ComEd's overall distribution system and, therefore, have a different cost of ***318** service than customers that utilize the ComEd distribution system at levels below 69,000 volts. ComEd currently provides a bill credit to high voltage customers under Rider 11 - Service at 69,000 Volts and Higher (‘Rider 11‘) for bundled electric service customers and Rider HVDS - High Voltage Delivery Service (‘Rider HVDS‘) for delivery service customers. Going forward, ComEd proposes this new delivery class to recognize the difference in cost to serve such customers, and to eliminate Rider 11 and Rider HVDS. ComEd indicates that this proposal also will allow for a more simplified billing procedure by applying standard delivery service charges for the High Voltage Delivery Class.

****173** ComEd opposes BOMA's proposal that ComEd maintain its current practice of providing a high voltage credit through Rider HVDS, noting that these customers will be treated the same under ComEd's proposal as they are today. According to ComEd, customers in the High Voltage Delivery Class will, in effect, be receiving the high-voltage credit through a reduced demand charge relative to other non-residential customers. ComEd argues that the maintenance of the current credit, in addition to the lower demand charge, would essentially provide an unwarranted double benefit to this class.

ComEd recommends that the Commission reject DOE's proposal that the High-Voltage Delivery Class be separated into two subclasses - those that take service over 69 kV and those that do not. ComEd further notes that DOE's position ignores the fact that customers in this class pay less than 1/2 cent per kWh for delivery service. ComEd articulated that DOE's proposal would not improve price signals and it would further complicate the billing process for ComEd.

BOMA

BOMA takes the position that the separate high voltage class approach proposed by ComEd does not have the same impact as the HVDS credit approach on non-high voltage over 10 MW consumers. (BOMA Ex. 3.0, pg. 9, ll. 179-181). BOMA witnesses Brookover and Childress testified that this is demonstrated by the 133% rate increase to non-high voltage over 10 MW consumers proposed by ComEd in this case. (BOMA 3.0, pg. 9, ll. 181-182). BOMA proposes that ComEd continue its current practice of providing a credit to high voltage consumers through Rider HVDS and allocating the lost revenues resulting from the credit to all nonresidential customer classes on an equal percentage, across-the-board basis. (BOMA Ex. 1.0, pg. 14, ll. 293-299).

DOE

DOE claims that ComEd's proposals leads to the peculiar result of extending high voltage discounts to low voltage loads. DOE also asserts that ComEd's proposal leads to significant reductions in rates for high voltage customers with loads up to 10,000 kW, but an ‘enormous‘ increase of 160 percent for high voltage customers with loads exceeding 10,000 kW. DOE argues that low voltage loads should not be included in the High Voltage class and believes there is no basis for extending the benefits of a high voltage discount to loads that are served at lower voltages. DOE proposes that the High-Voltage Delivery Class continue to be separated into two subclasses and that low voltage customers are billed at standard rates.

IIEC

With regard to the 10 MW and over customers served at 69 kV and over (the high voltage class), the current net charge of $1.04 per kW, IIEC recommends that they be increased or decreased in proportion to the overall revenue increase or decrease approved in this case. Under this approach, and assuming the Company's full requested revenue increase, IIEC says these customers will also see a 24.8% increase. According to IIEC, this increase is significantly higher than the increases to the remaining 69 kV customers, who would actually see decreases ranging from -31% to -35%.

Commission Analysis and Conclusion

****174 *319** ComEd currently provides a bill credit to high voltage customers under Rider 11 - Service at 69,000 Volts and Higher for bundled electric service customers and Rider HVDS - High Voltage Delivery Service for delivery service customers. In this case, ComEd proposes a new delivery class to recognize the difference in cost to serve such customers. ComEd argues that this proposal also will allow for a simplified billing procedure by applying standard delivery service charges for the High Voltage Delivery Class.

The DOE claims that ComEd's proposals leads to the peculiar result of extending high voltage discounts to low voltage loads. DOE also asserts that ComEd's proposal leads to significant reductions in rates for high voltage customers with loads up to 10,000 kW, but an ‘enormous‘ increase of 160 percent for high voltage customers with loads exceeding 10,000 kW.

The DOE argues that low voltage loads should not be included in the High Voltage class and believes there is no basis for extending the benefits of a high voltage discount to loads that are served at lower voltages. ComEd, on the other hand argues that there are two types of customers - those that take service over 69 kV and those that do not. It is ComEd's position that a proper rate design must contain a reasonable trade-off to avoid creating too few or too many rate classes. As a result, ComEd recommends that the Commission reject DOE's proposal that the High-Voltage Delivery Class be separated into two subclasses.

IIEC recommends that rates for the high voltage class be increased or decreased in proportion to the overall revenue increase or decrease approved in this case.

The Commission notes that DOE witness Swann stated: ‘I propose to separate the High Voltage (HV) class into two subclasses (below 69 kV and 69 kV and above) in order to eliminate the allocation of the costs of lower voltage facilities to customers who take service at voltage levels at or in excess of 69 kV and therefore do not use those facilities. …If the Commission adopts my proposal regarding a system-wide average increase in the Distribution Facilities Charges for customers with loads in excess of 10,000 kW, then this adjustment is moot.‘

Based on the Commission's conclusion reached in the Very Large Load Customer section of this order, DOE's concerns have been mitigated. Additionally, the Commission rejects IIEC's proposed methodology for increasing rates applicable to customers in the high voltage class. Given the other conclusions in this Order, the Commission believes that high voltage customers will not receive undue rate increases and the resulting rates will bear a reasonable relationship to the cost of providing service.

The only remaining issue is whether the discount associated with providing service to customers at high voltage should be extended to the portion of certain customers' load that is served at standard voltage. DOE objects to this proposal because it believes such discount would not reflect the cost of service. ComEd argues that the problem identified by DOE is immaterial and does not justify creating a separate rate class. In fact ComEd argues, ‘a proper rate design must draw the line at some point between too many rate classes and too few.‘ (ComEd reply brief at 122)

****175** While the Commission concurs that reducing the existing number of delivery rate classes is appropriate, it also believes ComEd proposal creates too few rate classes. ComEd's rationale for proposing the High Voltage Delivery Class was to take into account the fact that high voltage customers do not utilize a significant portion of ComEd's overall distribution system and therefore have a lower cost of service. However, the Commission cannot understand how this logic can be extended to the portion of customers' service provided at standard voltage. Thus, ComEd's proposal to extend the high voltage discount to service provided at standard voltage is rejected. ComEd is directed to file tariffs that comply with these findings and not to extend the high voltage discount to service provided at standard voltage.

****320** 3. RELATIVE CLASS ANNUAL UTILIZATION OF DISTRIBUTION FACILITIES*

ComEd

ComEd indicates that its ECOSS utilizes class NCP and CP demands to allocate distribution costs in a manner consistent with previous Orders approving ComEd's prior ECOSSs.*Seee.g.* , Commonwealth Edison Co. ICC Docket 01-0423 (Order, April 1, 2002). In particular, ComEd notes that its allocation methodology reflects the Commission's position that the interclass revenue allocation should be based on the principle of cost-causation, and that ‘distribution systems are designed primarily to serve demand.‘ *See Central Illinois Public Service Co.*, ICC Docket 00-0802 (Order, Dec. 11, 2001), at 42.

ComEd argues that CCC's proposal to use an allocation methodology that gives significant weight to the kWh consumption by class is arbitrary and results driven. According to ComEd, distribution costs are driven by the demands customers place on the system, as has been consistently recognized in the orders of this Commission. ComEd indicated that CCC's desired result is to reduce the revenue allocation to the residential class produced by the ECOSS. In other words, CCC seeks to shift costs away from the residential class and onto non-residential customers, using a methodology that has no cost basis.

CUB-CCSAO-City

CCC contends that as a matter of fairness and equity, the allocation of ComEd's revenue requirement among the rate classes should take into account relative class utilization of the distribution system. CCC notes that rate moderation is a well-established rate design principle, and that logically, rate mitigation should be applied, not just to ComEd's procurement of power, but to its distribution function as well. To mitigate the impact on residential customers of ComEd's proposed $135.7 million increase in residential distribution rates, CCC maintains that the Commission should consider criteria other than just cost of service, including average class utilization of distribution facilities and class risk differentials. CCC adds that adopting a reduced rate increase of $45.2 million - $90.5 million less than ComEd's proposed increase be based on Mr. Ruback's adjusted P&A cost of service study would appropriately reflect these key non-cost criteria.

****176** Additionally, CCC asserted that basing interclass revenue requirements entirely on cost ignores the limitations of cost of service studies. CCC argues that ComEd witness Heintz admitted under cross-examination that developing distribution demand allocators in cost of service studies is not an exact science, and accordingly requires some judgment. Mar. 27, 2006 Tr. at 1545. Further, Mr. Ruback testified that numerous methodologies with the potential for widely varying results can reasonably be used in conducting cost of service studies.

CCC further claims that adhering to the ECOSS in setting class revenue requirements is inappropriate given that this proceeding concerns retail distribution rates for a monopoly service. CCC asserts that basing revenue requirements on the system average rate of return is proper in determining wholesale and jurisdictional revenue requirements, which do not implicate rate impacts on particular classes, but not in establishing inter-class retail distribution revenue requirements.

Commission Analysis and Conclusion

The Commission's conclusion regarding this issue is stated above in ‘Allocation of Distribution Costs.‘

4. ENVIRONMENTAL COST RATE REDESIGN

ComEd

[83-85] ComEd states that its Customer Charge is a fixed monthly charge that is designed to recover the customer-related costs that do not vary by the amount of electricity delivered to customers. Alongi/McInerney Dir., ***321** ComEd Ex. 10.0, 19:474-20:480. The Customer Charge recovers costs such as those related to billing, payment processing, and other customer services, as well as certain costs associated with uncollectible accounts.*Id.*;*see also* ComEd Ex. 11.1.

ComEd explains that, if adopted, Staff's proposal to implement a lower fixed charge in conjunction with a higher usage charge would seriously impede ComEd's ability to recover its costs. ComEd indicated that, according to Staff's direct testimony, the goal of the proposal was to reduce customer usage. If usage is reduced, all else being equal, then ComEd's ability to recover its costs is at risk.

ComEd identifies the crux of the problem as the lack of empirical evidence supporting the proposed 20% shift. ComEd points out that Staff does not cite any evidence or provide any analysis regarding the impact of the proposal on usage. ComEd argues that the impact on usage only can be determined through a study of the price elasticity of demand and no such study has been produced by Staff, who is advancing this proposal. Crumrine Sur., ComEd Ex. 40.0 Corr., 49:1109-18. Thus, ComEd avers, it is impossible for the Commission to determine what impact a shift of dollars from the Customer Charge to the DFCs would have on customer usage. Crumrine Reb., ComEd Ex. 23.0, 41:868-85. In other words, ComEd continues, any rate design that reduces customer usage also must factor in a corresponding upward adjustment to the billing determinants to account for the reduction in revenues that would otherwise occur.*Id.*

****177** ComEd comments on other deficiencies in Staff's proposal as well. For example, Mr. Lazare testified that ComEd's rates ‘fail to take into account … the environmental cost of producing power.‘ Lazare Dir., Staff Ex. 6.0 Corr., 37:909-13. However, ComEd notes, the purpose of this case is to set delivery rates - which by definition, exclude the cost of producing power.

ComEd notes that IIEC also opposed Staff's adjustment. IIEC's witness Stephens testified that ‘[t]he most efficient pricing is to have delivery charges that are based on the cost of delivery and, more particularly, to have customer charges recover customer-related costs and to have demand charges recover demand-related costs.‘ Stephens Reb., IIEC Ex. 5.0, 21:485-88. Mr. Stephens also stated that it would be ‘purely speculative to assert that such marginal changes [on the total customer bills] (some of which are decreases) would elicit any meaningful reduction in pollutants… .‘*Id.* at 22:500-2.

Staff

Staff recommends that environmental costs be factored into usage charges. (ICC Staff Exhibit 6.0 Corrected, pp. 38, 41) Staff avers that ComEd's proposed rate design fails to account for the environmental cost of producing power, such as costs associated with global warming. Staff argues that there is a correlation between societal environmental costs and usage (*i.e.*, increased usage generally results in increased environmental impacts), and that rates should be designed to increase recovery of the revenue requirement through usage sensitive charges to reflect the increased environmental costs imposed by higher usage.

Staff proposes that all facilities charges for ComEd customers should be reduced by 20%. There would also be a corresponding increase in delivery and demand charges to allow ComEd to recover the lost revenue from customers. Staff states that its proposal is designed to be revenue neutral on a class basis, meaning, residential delivery charges would be raised to the level that fully offsets the revenue loss from the reduction in residential facilities charges. Staff believes that this environmental rate redesign for residential customers will have no impact on non-residential rates. Similarly, the corresponding rate redesigns for individual non-residential classes would not affect rates for other non-residential classes or for residential customers. (ICC Staff Exhibit 6.0 Corrected, p. 43)

Staff argues that environmental costs are real, but are also quite difficult to quantify; that the cost to society from consumption of a kWh of electricity is virtually impossible to measure. It is Staff's position that energy consumers contribute***322** to the problem of global warming through their consumption of fossil fuels, whether to power an automobile, heat a home or to use electricity. According to Staff, those electricity demands are met at least in part by power plants that consume fossil fuels and release carbon dioxide which is considered the primary contributor to global warming. (ICC Staff Exhibit 6.0 Corrected, p. 37) Therefore, Staff argues it is relying on experience to develop its 20% reduction figure. Staff's rationale is that the selection of a 20% reduction in customer charges recognizes that environmental impacts are indeed significant; however, it still permits the utility to recover 80% of customer costs through up-front monthly charges. Staff proffers that this is a reasonable tradeoff between the interests of the environment and the utility. (ICC Staff Exhibit 6.0 Corrected, p. 43)

****178** Staff states that its proposal provides a price signal to ratepayers that more accurately reflects the impact of their consumption on the environment. Therefore, its proposal will promote consumer consideration of environmental concerns in consumption decisions. Moreover, Staff avers that the impacts of its proposal on ratepayers would be relatively minimal.

Staff's proposal is not intended to increase the overall rates paid by ComEd customers, and would have a relatively minimal impact on ratepayer electricity usage, when compared to other factors being reviewed in this case. Staff proposes to shift recovery of the revenue requirement from customer charges to delivery charges. If bills for some customers rise, then bills for others would decline. This would be a zero sum game from a revenue standpoint. (ICC Staff Exhibit 6.0 Corrected, 41-42; ICC Staff Exhibit 17.0 Corrected, p. 32)

In support of its proposal, Staff relies upon Rider 31, as setting precedent for recovery of environmental costs in delivery rates. ComEd's existing Rider 31, Decommissioning Expense Adjustment Clause, recovers nuclear decommissioning costs through a rider that ‘is applicable to each and every kilowatt-hour (kWh) of electricity delivered or sold at retail in the Company's service area, including, but not limited to, sales by the Company to tariffed services retail customers, sales by the Company to retail customers pursuant to special contracts or other negotiated arrangements, sales by alternative retail suppliers, and sales by an electric utility other than the Company… .‘ (ILL. C.C. No. 4, 7th Revised Sheet No. 95.09.4 (Cancelling 6th Revised Sheet No. 95.09.4)) Staff avers that this is a clear example of ComEd recovering an environmental cost associated with electric generation from the delivery component of ratepayer bills. (ICC Staff Exhibit 17.0 Corrected, pp. 30-31)

Staff avers that its proposal is more reasonable than the two alternatives proffered by ComEd. Staff finds ComEd's proposals to be problematic. The first alternative is to incorporate these charges into the cost of power received through the auctions. The second alternative is to do nothing at all.

Staff finds that incorporating environmental costs into auction power prices is problematic because environmental costs may arise not just for power received through the auction process, but also for unbundled power purchased from a Retail Electric Supplier (‘RES‘). If environmental costs were only reflected in power received through the auction, the relative cost of bundled power could rise and shift demand to RES-supplied power, regardless of the relative environmental impacts. (ICC Staff Exhibit 17.0 Corrected, p. 30)

The second alternative - doing nothing - is most problematic of all. Staff refers to a statement from the U.S. Environmental Protection Agency that outlines the problem as follows:

Rising global temperatures are expected to raise sea level, and change precipitation and other local climate conditions. Changing regional climate could alter forests, crop yields, and water supplies. It could also affect human health, animals, and many types of ecosystems. Deserts may expand into existing rangelands, and features of some of our National Parks may be permanently altered. http://yosemite.epa.gov/OAR/globalwarming.nsf/content/Im pacts.html.

***323** (ICC Staff Exhibit 17.0 Corrected, p. 30)

IIEC

****179** IIEC objects to Staff's proposal to change ComEd's rate design to increase usage and demand charges and reduce customer charges to account for environmental cost of producing power. It believes the most efficient pricing mechanism, in a delivery service case, is to price delivery charges on the cost of delivery service. More particularly, IIEC says customer charges should recover customer related delivery costs and demand charges should recover demand related delivery service costs. IIEC points out the environmental problems of concern to Mr. Lazare are associated with the production of electric power and energy, not its delivery. The cost of generating power already reflects the environmental cost of production to the extent society has deemed appropriate according to IIEC. Thus, IIEC says customers, whether they purchase the power through the ComEd auction, or from third-party suppliers, are already paying power costs that include the environmental costs of concern to Staff.

IIEC also says Staff's proposed rate design has not been proven and cannot be proven to have the effect of minimizing any detrimental effects on the environment. This is because the rate design will have marginal impact on customer distribution bills and little impact on the total bill for electric service. IIEC says the change might actually decrease the overall delivery service charges for some customers while increasing charges to others. Therefore, it would be nothing more than speculative to suggest that marginal changes in the distribution portion of the customers' bills (increases and decreases) will elicit any meaningful reduction in pollution. Thus, IIEC recommends Staff's proposal be rejected.

Commission Analysis and Conclusion

Staff is proposing a 20% reduction in all facilities charges to address the environmental impact related to the production of electricity. The proposal by Staff also includes a corresponding increase in delivery and demand charges to allow ComEd to recover the lost revenue from customers. Staff argues that energy consumers contribute to the problems with global warming through the consumption of fossil fuels such as using electricity, powering a car or heating a home. It is Staff's position that ComEd is not doing enough to protect the environment. ComEd and IIEC oppose Staff's recommendation, arguing that it would contribute to rates that are not reflective of costs.

The Commission agrees with Staff that environmental concerns and global warming are growing problems that require the attention of society, including this Commission. Staff's witness Mr. Lazare indicated that ComEd needs to consider the environmental implications of producing electricity. This is a statewide public policy issue related to the production of electricity, however.

As the Commission understands it, the proposal of Staff would shift approximately $70 million from the Customer Charge to usage or demand-based charges. As with similar issues, the Commission believes it is necessary to determine whether there are sufficient public policy considerations that warrant deviating from cost-based rates.

****180** Having reviewed the record in its entirety, the Commission rejects Staff's proposal. While the Commission shares Staff's concerns over the environmental impact of generating electricity, the Commission believes that a 20% shift in the recovery of costs from the customer charge to the delivery charge is unwarranted. Elsewhere in this Order and in other docketed proceedings, the Commission is taking affirmative steps to encourage conservation and off-peak usage of electricity. All things considered, the Commission believes Staff's proposed twenty percent adjustment, as it would apply to ComEd, should be rejected, because it results in the recovery of what are largely fixed costs through variable charges. This shift in cost recovery, which potentially exposes ComEd to the risk of underrecovery, is not warranted.

5. RIDER ECR

ComEd

***324 [86-92]** ComEd proposes that all of its incremental environmental remediation costs be recovered through a new rider, Rider ECR, rather than through base rates. The record contains clear evidence that ComEd incurs costs relating to environmental clean-up or remediation at various sites, and that these costs are prudent and reasonable.

ComEd defines incremental environmental remediation costs to include all outside contractor and legal costs related to remediation at both sites related to historic manufactured gas plants ('MGP') and non-MGP sites where contamination has occurred, for example, from adjacent sites or because of contamination left by prior owners. According to ComEd, these costs include emergency response work performed by outside contractors (Fernandes/McCauley Reb., ComEd Ex. 28.0, 11:242-12:262), but do not include internal costs or payments made to affiliates for work performed by the affiliate (Fernandes/McCauley, Tr. at 2096:3-7).

ComEd witnesses described how and why these costs are incurred and the controls that ComEd has in place to ensure that the level of cost incurred is reasonable. ComEd witnesses further explained that these costs fluctuate along with ever-changing state and federal environmental laws, with which ComEd must comply if it is to avoid civil and criminal penalties and stay in business. Fernandes/McCauley Reb., ComEd Ex. 28.0, 7:140-49, 8:162-74, 13:279-87, 14:315-19, Att. C. ComEd included with its testimony the outside contractor and legal costs that were actually incurred by the company for both MGP and non-MGP sites between the years 2001 and 2004. Fernandes/McCauley Sur., ComEd Ex. 44.0, Att. 2. ComEd notes that these data show wide fluctuation in environmental remediation costs over this time period.

ComEd stressed in its testimony that both MGP and non-MGP costs should be recovered under Rider ECR as they are similar in nature. Moreover, ComEd argued that the MGP/non-MGP distinction is purely arbitrary, because environmental laws do not distinguish between these types of costs. Fernandes/McCauley Reb., ComEd Ex. 28.0, 7:140-49. Further, both types of costs vary widely from year to year according to ComEd. Because such costs are volatile, fluctuating and unpredictable, ComEd stated that it is very difficult to make a test-year estimate that would both ensure adequate cost recovery by ComEd and avoid overpayment by its ratepayers.*See* Hill, Tr. at 838:2839: 1; Fernandes/McCauley Reb., ComEd Ex. 28.0, 2:38-41. ComEd explains that a rider ensures that ComEd recovers, and its customers pay, only the costs incurred, no more and no less. Moreover, Rider ECR provides for annual reconciliation proceedings through which the Commission will review whether the costs ComEd seeks to recover were prudently incurred. ComEd argues that such proceedings therefore ensure, going forward, that the costs it seeks to recover are prudent and that rates are just and reasonable. In short, ComEd requests that both MGP and non-MGP costs be recovered through Rider ECR.

****181** ComEd notes, as a preliminary matter, that no party introduced any evidence showing its environmental costs to be unjust or unreasonable, that ComEd otherwise could avoid these costs, or that ComEd was not entitled to recovery of these costs. ComEd avers that Staff unequivocally supports rider recovery for MGP costs. Ebrey Dir., ICC Staff Ex. 2.0, at 32:668-75; Ebrey, Tr. at 1904:16-18. Further, although IIEC witness Gorman opposed rider recovery in his pre-filed testimony, during the hearings he acknowledged that the Commission has already permitted the recovery of MGP remediation expenses through a rider and stated that IIEC is ‘not suggesting the Commission should reverse any findings already made.‘ Tr. at 2045:5-10. City witness Walter similarly indicated that the Commission has previously approved rider ‘recovery of MGP-related remediation costs‘ (Walter Reb., City Ex. 2.0, 3:53-4:55), and specifically stated that the City did not oppose ComEd's recovery of its environmental costs (Walter, Tr. at 680:1-6).

ComEd responds to the parties' argument that, because ComEd is not seeking rider recovery for its storm-related expenses, it should not be allowed to ask for rider recovery for its non-MGP costs. ComEd points out that the parties ***325** mischaracterized the record and misstated ComEd witness Mr. Hill. During cross-examination, Mr. Hill explained that non-MGP costs are uniquely and inherently unpredictable compared to the other kinds of costs that ComEd incurs. While Mr. Hill agreed that storm restoration costs are volatile, he went on to testify that ‘[t]hey're not unpredictable. What you do know is they will occur.‘ Tr. at 889:16-17. Mr. Hill further explained that, in contrast, the unpredictable nature of the non-MGP remediation costs is ‘driven oftentimes by changes in public sentiment, legislative action, changes in governmental limitations.‘ Hill, Tr. at 890:11- 13 *see also id.* at 838:9-13; Fernandes/McCauley Reb., ComEd Ex. 28.0, 13:276-14:301.

ComEd points out that the position offered by other parties that it not be permitted to recover environmental remediation costs from its delivery services customers was inconsistent with the opinions of this Commission and the Supreme Court of Illinois. ComEd argues that the Commission has previously rejected that position, noting that these types of costs ‘are corporate expenses that should not be bypassed by any retail customer.‘ *Commonwealth Edison Co.*, ICC Docket No. 01-0423, (Order, Mar. 28, 2002), at 105. Similarly, the Illinois Supreme Court has recognized that payment of environmental remediation costs ‘allows a utility to remain in business and to continue to provide service to its customers,‘ and are a ‘necessary expense of utility operations‘ that the utility is entitled to recover.*Citizens Util. Bd. v. Ill. Commerce Comm'n,* 166 Ill.2d 111, 123 (1995). Thus, ComEd states that all customers benefit from, and should contribute to, recovery of these costs.

ComEd also addresses the suggestion by Staff and the City of Chicago that recovery of non-MGP costs, whether by rider or otherwise, be deferred to a separate proceeding. ComEd argues that ‘the genesis of MGP riders was, in fact, utility rate cases.‘ Crumrine Sur., ComEd Ex. 40.0, 67:1517-20 (*citing* ICC Docket No. 90-0127 (Order on Remand, June 8, 1994); ICC Docket No. 91-0010 (Order, Nov. 8, 1991)). ComEd also notes the existence of annual reconciliation proceedings under Rider ECR, through which the Commission may review whether the costs ComEd seeks to recover were prudently incurred. In addition, in response to Staff's argument opposing the proposed September 30 reconciliation period in favor of a December 31 reconciliation period, ComEd witness Mr. Crumrine testified that ComEd prefers the timing of the September date because it would impose less of a burden on ComEd's staff. Crumrine Reb., ComEd Ex. 23.0, 68: 1457-62. ComEd also explains that individual costs such as litigation expenses would be reviewed for reasonableness during the annual reconciliation hearings. Fernandes/McCauley Reb. ComEd Ex. 250, 14:319-15, 326. With regard to Staff's proposal concerning insurance recovery, ComEd explains that all such insurance recovery has been exhausted. Hill Sur., ComEd Ex. 36.0, 50:1123-29; Crumrine Sur., ComEd Ex. 40.0, 71:1617-19; Fernandes & McCauley Sur., ComEd Ex. 44.0, 3:62-67; ComEd's Response to Staff's (TEE) Data Request 19.05.

****182** With respect to IIEC witness Gorman's argument regarding rider recovery and return on equity, ComEd responds that IIEC misstated the Commission standard. It argued that this has never been the standard for approving such riders, and it is not the standard today. ComEd further points out that Mr. Gorman's testimony in this proceeding is inconsistent with his testimony in the 'Coal Tar Cases,' where he 'testified that because remediation expenditures will fluctuate significantly from year to year, including a representative amount as a test year expenditure would in effect be asking the Commission to allow an expense that is not known and measurable,' and 'recommended that the Commission may want to consider extraordinary treatment for remediation expenditures.' *Commonwealth Edison Co.*, 1992 Ill. PUC Lexis 379 at *113-14;*see also* Crumrine Reb., ComEd Ex. 23.0, 62:1320-34. And, in response to Mr. Gorman's argument that ComEd has been fully recovering its MGP costs through base rates, ComEd cited the record evidence to the contrary, pointing out that it had recovered ***326** far less in rates than it had incurred. Fernandes/McCauley Reb., ComEd Ex. 28.0, 5:104-106:125.

Finally, ComEd denies the assertion of City witness Walter that the delay in ComEd's filing of Rider ECR somehow suggests that environmental remediation costs are not as volatile or unpredictable as ComEd alleges. ComEd observed that, subject to the 'Coal Tar Cases' and the restrictions of the 1997 Restructuring Act, it has been subject to a rate freeze since December 1997 (Crumrine Sur., ComEd Ex. 40.0, 69:1561-72), and that it was not until after the rate freeze was already in effect that ComEd received information regarding increased estimated liability for environmental costs on its MGP sites. Fernandes/McCauley Reb., ComEd Ex. 28.0, 6:130-35.

Staff

Staff witness Ebrey testified that she supports ComEd's proposal to recover manufactured gas plant ('MGP') remediation costs (also known as 'coal tar' costs) through Rider ECR rather than through base rates. (ICC Staff Exhibit 2.0, p. 32) However, Ms. Ebrey disagreed with ComEd's proposal to recover internal Company costs and other costs in addition to coal tar costs through Rider ECR rather than through base rates. (*Id.*) With respect to these concerns, Ms. Ebrey proposed (1) the appropriate language changes to Rider ECR, (2) an adjustment to include the internal Company costs in the Company's test year operating expenses, and (3) language consistent with that in other utilities' coal tar riders relating to costs associated with former MGP sites, costs paid to outside vendors, insurance recoveries, the measurement period for costs and recoveries, the formula for the ECR charge, provisions for mid-year revisions of the ECR charge, annual reconciliation proceedings, and the filing date and effective date of ECR charge revisions. (ICC Staff Exhibit 2.0, pp. 30-39)

Staff notes in its Initial Brief that ComEd (1) indicated that any costs excluded from Rider ECR should be added back to the test year jurisdictional operating expenses (ComEd Ex. 19.0 Revised, pp. 62-63) and (2) accepted some of the proposed revisions to Rider ECR and rejected others. (Staff IB, p. 100) Further, Staff states that ComEd accepted the following revisions proposed by Staff witness Ebrey:

****183** 1. Exclusion of internal wages and salaries. However, the Company does not address the exclusion of payments to affiliates in its rebuttal testimony. (ICC Staff Exhibit 2.0, pp. 35-37). Ms. Ebrey testified that she continues to propose that language change in Rider ECR. (ICC Staff Exhibit 13.0, Attachment C)

2. Revisions of ECR Adjustment between annual calculations,

3. Prudence review and annual reconciliation process,

4. Exclusion of land acquisition costs, and

5. Ordered Reconciliation Factor. (*Id.*, pp. 100, 102)

However, Staff adds that ComEd rejected revisions proposed by Staff witness Ebrey relating to the exclusion of non-MGP related costs, the calendar year reconciliation cycle, and the inclusion of all insurance recoveries. (*Id.*) Staff accepted the January 2, 2007 effective date of the initial Rider ECR as proposed by ComEd but notes that future annual adjustments to the ECR charge should be at an effective date of January 1 each year (ICC Staff Exhibit 13.0, p. 36)

In her rebuttal testimony, Staff witness Ebrey explained that information provided by the Company calls into question the recoverability of the specific non-coal tar costs. She stated that since ComEd had not shown these costs to be reasonable, prudently incurred and related to its delivery service business, Ms. Ebrey could not recommend they be recovered through either Rider ECR or base rates. (ICC Staff Exhibit 13.0, pp. 30-31) While ComEd offered testimony discussing the volatility of the non-MGP costs in its attempt to draw a favorable comparison between MGP and non-MGP environmental costs, Staff argues that ComEd's own witness refuted such testimony by confirming***327** that other costs of similar volatility are recovered through base rates. (Staff IB, p. 101) Further, Staff notes that while ComEd attempted to graphically show that both MGP and non-MGP costs are similarly volatile (ComEd Exhibit 44.0, Attachment 1), the Company witnesses admitted during cross-examination that if the scale used for both graphs had been the same, the comparable volatility would be drastically different. (*Id.*) Thus, Staff argues that the facts demonstrate that non-MGP costs are much less volatile than MGP costs. (*Id.*)

In its Initial Brief, Staff states that while ComEd uses the generic coal tar order as its basis for proposing recovery of environmental costs through Rider ECR in the instant proceeding, Company witness Crumrine agreed that, based on his definition of non-MGP costs, the generic coal tar order does not address those types of costs. (Staff IB, p. 102)

Regarding the calendar year reconciliation cycle, Ms. Ebrey noted that ComEd has not shown why it should be given preferential treatment for a September 30 reconciliation period. Ms. Ebrey continues to propose a December 31 reconciliation period consistent with that used by other utilities whose annual reporting period is a calendar year. (ICC Staff Exhibit 13.0, p. 36) In its Initial Brief, Staff argues that ComEd witness Crumrine contradicted the Company's claim that an annual reconciliation as of September 30th would avoid the possible need to increase staffing when he testified that he had not quantified the claim for the need for increased staffing due to a year-end reconciliation. (Staff IB, p. 102)

****184** Regarding insurance settlements, Ms. Ebrey testified that since ComEd is currently in negotiations with its insurance carriers, it is reasonable to assume that some sort of settlement will be reached in the future. (ICC Staff Exhibit 13.0, p. 37) She stated that any benefits from insurance recoveries should be realized by the parties who have borne the costs related to those recoveries, regardless of when the funds are received. (*Id.*) Ms. Ebrey added that since it is doubtful that the settlement amount will be directly relatable to specific costs incurred and would more likely be related to the Company's liability at all of its MGP sites, she proposed that at the time of any insurance recoveries, the Company would file a revised Rider ECR resetting the rate to zero. (*Id.*) She testified that the insurance recoveries should then be used to cover any on-going remediation costs at the Company's MGP sites with interest being credited annually to the unexpended insurance proceeds at ComEd's after tax cost of capital from this rate case, to be updated at the time of subsequent rate cases. (*Id.*, pp. 37-38) It is Ms. Ebrey's position that once the insurance recoveries (plus interest) have been depleted to cover on-going remediation costs, Rider ECR could be revised based on the formula in the tariff. (*Id.*)*City-CCSAO*

City-CCSAO maintains that ComEd's proposed Rider ECR should be rejected because ComEd has failed to demonstrate that rider recovery of environmental costs relating to sites other than Manufactured Gas Plant (‘MGP‘) sites is warranted. City-CCSAO notes that it would not oppose Rider ECR if it were limited to MGP costs, given that the Commission approved rider recovery of such costs in the final order in Dockets 91-0080 through 91-0095 (cons.) (the ‘Coal Tar Order‘). City-CCSAO adds that the Coal Tar Order did not address non-MGP costs, *see* Mar. 30, 2006 Tr. at 2312 (Crumrine), and the environmental cost recovery riders of all other Illinois utilities are limited to recovery of MGP-related remediation costs.

With respect to rider recovery in general, City-CCSAO contends that dollar-for-dollar recovery of costs can create perverse incentives for utilities, as the Commission recognized in adopting a uniform fuel adjustment clause ('FAC ') providing for automatic flow-through to ratepayers of fuel costs incurred by electric utilities. Specifically, City-CCSAO explains that in Docket No. 78-0457, the Commission emphasized that '[i]t is absolutely essential, if fuel adjustment clauses are to be used correctly, that the manner by which a utility acquires, handles and accounts for fuel supplies be wholly prudent and defensible.' 45 Pub. Util. Rep. 4th at 19.

***328** Moreover, City-CCSAO argues, ComEd has failed to show that its non-MGP costs are so 'unexpected, volatile, or fluctuating' as to warrant rider recovery.*Citizens Utility Bd. v. Ill. Commerce Comm'n,* 166 Ill. 2d 111, 138 (1995) ('*CUB v. ICC* '). In particular, City-CCSAO maintains that ComEd has not established that 'constantly evolving state and federal environmental laws' make non-MGP costs unpredictable and volatile. ComEd Ex. 28.0 at 7, L. 141-44. Although ComEd points to an attachment depicting various federal and state environmental laws and the dates they were amended, see ComEd Ex. 28.0, attach. City-CCSAO asserts that attachment C is not a reliable indicator of the environmental laws that drive ComEd's environmental costs. Indeed, City-CCSAO adds, Messrs Fernandes and McCauley acknowledged on cross-examination that a particular law's inclusion in attachment C does not signify that ComEd is liable or potentially liable under that law. Additionally, City-CCSAO argues that ComEd has not shown that all of the costs that would flow through Rider ECR are, in fact, mandated by federal or state law.

****185** City-CCSAO further argues that ComEd has not explained why non-MGP costs are appropriate for rider recovery even though other volatile and unpredictable costs are recovered through base rates. In particular, City-CCSAO cites ComEd's storm restoration costs as an example of volatile and unpredictable costs that ComEd has not claimed should be recovered outside the traditional rate processes. Moreover, City-CCSAO notes that the $18,320,000 in storm restoration costs ComEd has included in operating expenses in this case dwarfs the $1,466,667 ComEd asks the Commission to add back to its test-year revenue requirement if rider recovery of non-MGP costs is rejected.

In addition, City-CCSAO contends it is unclear why, if ComEd's environmental costs are as volatile and unpredictable as the utility alleges, ComEd waited until this proceeding to seek rider recovery of such costs. City witness Steven Walter testified that ComEd could have filed a rider to recover MGP remediation costs in the five years between the Commission's issuance of the Coal Tar Order and the commencement in 1997 of the rate freeze. And because the Coal Tar Order was not stayed pending appeal, City-CCSAO adds that ComEd could have filed a rider recovering MGP costs between 1992 and 1995, while the Coal Tar Order was being appealed. Indeed, City-CCSAO notes that Mr. Crumrine acknowledged that Ameren IP's Rider EEA, which recovers MGP remediation costs, applies to all customer billings on or after April 29, 1993 well before the Illinois Supreme Court issued its decision reviewing the Coal Tar Order.

Finally, City-CCSAO claims that ComEd's attempt to assure the Commission that it has adequate procedures in place to control environmental costs is unconvincing. Mr. Walter testified that the cost management procedures ComEd identifies - competitive bidding of environmental projects, task-based billing estimates and billing, reporting requirements to monitor project status and evaluation of ComEd employees' cost management efforts - are not extraordinary and are regularly employed by prudent businesses. Moreover, City-CCSAO states that ComEd voluntarily adopted and follows these procedures, and has identified no legal mandate that it maintain them. Additionally, City-CCSAO argues that ComEd's procedures do not cover the costs of significant activities expressly covered by Rider ECR, including litigation and settlement of environmental claims.

To the extent the Commission is not inclined to reject Rider ECR outright, City-CCSAO asserts that a separate proceeding should be initiated to consider whether rider recovery of non-MGP costs is appropriate. City-CCSAO notes that such recovery would represent a substantial policy change, as none of the environmental cost recovery riders of the Illinois utilities other than ComEd covers non-MGP-related remediation costs, and Staff agrees that a separate proceeding is warranted to address the matter. City-CCSAO further asserts that the proceeding that culminated in the Coal Tar Order was, in fact, a stand-alone proceeding, *CUB v. ICC,* 166 Ill. 2d at 118, as was the proceeding in which the Commission ***329** approved ComEd's current Rider 28.*See City of Chicago v. Ill. Commerce Comm'n,* 264 Ill. App. 3d 403, 405 (1st Dist. 1993). In addition, City-CCSAO contends ComEd's professed concern that had it filed Rider ECR in a separate proceeding, the filing would likely have been attacked as forbidden ‘single-issue ratemaking‘ is unfounded because the Illinois Supreme Court rejected this very argument in *CUB v. ICC.*

IIEC

****186** IIEC recommends Rider ECR as proposed by ComEd be rejected. ComEd proposes to recover all incremental costs incurred by the Company in association with Environmental Activities under the Rider. ComEd identifies two categories of cost recovery - MGP site costs and non-MGP site costs, including ComEd's Superfund and leaking underground storage tank program costs.

IIEC says ComEd has shown no economic justification for Rider ECR. ComEd, according to IIEC, has been recovering through base rates the costs it now proposes to recover through a rider. ComEd has consistently rejected the option of seeking rider recovery. (IIEC notes that ComEd did this despite the alleged volatile, unpredictable nature of the costs.) ComEd has failed to show that the expenses to be recovered by Rider ECR are significant, volatile, and outside of management's control, or would impede the Company's ability to earn its authorized return from regulated utility operations. As a result, IIEC argues a special rider recovery mechanism is not warranted.

IIEC presented evidence regarding the magnitude of the costs involved. Mr. Gorman observed that a variation in operating expense of $1.5 to $2 million - approximately the size of ComEd's annual non-MGP expenses - would change ComEd's operating income by approximately $.9 to $1.2 million and change ComEd's earned rate of return by only 0.02% (earned ROE by 0.04%), assuming ComEd's proposed capital structure and rate base. An expense deviation of about $4 million - an approximation of the largest recent variation in ComEd's MGP expenses - would change its earned rate of return and ROE by 0.4% and 0.7% respectively, using the same assumptions. It is reasonable to expect that these costs may be under-recovered in some years and over-recovered in other years, with full recovery likely over time. In neither case is the variation significant enough to impair ComEd's ability to earn its authorized return.

IIEC reasons that the environmental costs are similar in their unpredictable nature to storm costs, yet ComEd does not have a rider recovery mechanism for storm costs. Finally, IIEC points out that the Commission has the discretion to deny the use of a rider in this case and it should exercise its discretion to reject Rider ECR in his case.

IIEC argues that if the Commission accepts its recommendation, ComEd should be permitted to add back to its cost of service the same $3 million amount that was removed from the Company's revenue requirement in preparation for recovering these costs through Rider ECR. IIEC points out that ComEd suggested it should be permitted to add $11.577 million of expenses to the Company's cost of service - not the $3 million actually removed. However, according to IIEC, adding back more expenses than were actually removed in the first instance would over-recover ComEd's actual environmental expenses.

IIEC recommends ComEd's proposed Rider ECR should be rejected and its environmental expenses recovered through base rates, and ComEd should be permitted to add back to its revenue requirement only the $3 million it had removed.

Commission Analysis and Conclusion

****187** ComEd has demonstrated that its incremental environmental costs are volatile and fluctuating. No party has disputed this. The Illinois Supreme Court has explicitly stated that 'a rider mechanism is effective and appropriate for cost recovery when a utility is faced with unexpected, volatile, or fluctuating expenses.' *See Citizens Util. Bd. v. Ill. Commerce Comm'n,* 166 Ill.2d 111, 138 (1995) (*citing* ***330***City of Chicago v. Ill. Commerce Comm'n,* 13 Ill.2d 607 (1958)). Furthermore, this Commission, in the 'Coal TarCases,' designated cost-tracking riders as the preferred method for the recovery of MGP site remediation costs. Docket Nos. 91-0080 through 91-0095 (Cons), 1992 Ill. PUC Lexis 379 at *136 (Order, Sept. 30, 1992).

In particular, it seems clear that ComEd's incremental environmental costs related to MGP sites should be recovered through Rider ECR. Staff supported the recovery of such costs, and while the opposition of IIEC and the City was broader than Staff's, even those parties admitted that the Commission has previously permitted the recovery of environmental remediation costs related to MGP sites. The City stated in its brief that it would not oppose rider recovery for MGP-related costs. Rider recovery is appropriate to ensure that ComEd recovers, and its customers pay, no more and no less than the costs incurred. The Commission therefore rejects the argument that these incremental environmental costs be recovered through base rates, rather than through a rider. The Commission finds that MGP-related environmental remediation costs shall be recovered through Rider ECR.

ComEd also wants to include non-MGP costs in its proposed Rider ECR. This is opposed by all of the other interested parties. Based on ComEd's own graph (Exhibit 44.0 - Attachment 1) and the testimony of ComEd's own witness, the non-MGP costs are not as large or as volatile as the MGP costs. The Commission agrees with Staff that the Company has failed to demonstrate that non-MGP costs are reasonable, prudently incurred, related to delivery costs and are as volatile as MGP costs. The Commission also notes that there is no precedent for recovery of non-MGP costs through a rider. The Coal Tar Cases only involved costs related to MGP sites. Therefore, the Commission rejects the inclusion of non-MGP costs in the proposed Rider ECR.

The Commission agrees with several of the revisions of Rider ECR as proposed by Staff. In particular, ComEd's internal wages and salary expense, as well as any land acquisition costs, shall all be excluded. The calendar reconciliation cycle will end on December 31, consistent with other utilities whose annual reporting period is a calendar year. The Commission also concludes that any benefit that the Company receives from insurance proceeds related to environmental recoveries, no matter when received, should be included in any revisions of ECR adjustments between annual calculations.

In summary, the Commission concludes that Rider ECR will cover only MGP related costs. Since non-MGP related costs are not to be included under this Rider, the Commission concludes that $1,466,667 will be added back into the test-year revenue requirement. Therefore, the Commission approves Rider ECR as amended above.

6. RIDER AC7

ComEd

****188 [93, 94]** ComEd proposes to replace its current Rider AC with Rider AC7, which ComEd indicates would continue to compensate residential customers for reducing load by permitting ComEd to install a direct load control ('DLC ') device that cycles a customer's central air conditioning unit compressor.

ComEd describes technical modifications to its original proposed Rider AC7 in order to provide an appropriate transition for customers from ComEd's existing Rider AC to Rider AC7. ComEd indicates that the modifications stem from the creation of the new rates book and would not impact the compensation to such customers.

Staff

Staff does not object to ComEd's proposed Rider AC7 - Residential Air Conditioner Load Cycling Program 2007. (ICC Staff Exhibit 6.0, pp. 51-52) Rider AC7 offers residential customers a monthly discount during the Summer months in compensation for installing direct load controllers on their air conditioners. The load controllers mitigate peak demands, thereby reducing ComEd's overall capacity needs and costs. (*Id.*) ComEd is proposing to maintain the ***331** current rate of compensation to customers, which increases its costs by $1,168,961. Lowering the compensation to customers increases the potential that participation in the program will fluctuate. Staff finds value in maintaining participation in demand-side programs and, therefore, finds it reasonable to maintain the rates at current levels.

Commission Analysis and Conclusion

It appears to the Commission that no party objects to Rider AC7 as proposed by ComEd and modified in its surrebuttal testimony. Accordingly, Rider AC7 is hereby approved.

7. RIDER CLR7

ComEd

ComEd proposes to replace its current Rider CLR with Rider CLR7. Rider CLR7 also is discussed in the discussion of Riders ISS, 13, 26, 27, 30 and 32 in Section II.I.7 of this Order, *infra*.

ComEd proposed technical modifications to Rider CLR7 in order to provide an appropriate transition for customers from ComEd's existing interruptible/curtailable rider to Rider CLR7, as well as clarifying how compensation under Rider CLR7 is provided.

Staff

Staff does not object to ComEd's proposed Rider CLR7 - Capacity-Based Load Response and System Reliability Program 2007. (ICC Staff Exhibit 6.0, pp. 45-46) ComEd proposes two new riders, one of which is Rider CLR7, to provide customers service options consistent with the auction process for bundled service and PJM-based energy and capacity credits for interruptible service. Rider CLR7 is consistent with ComEd's procurement of energy through an auction process, which will commence in 2007. (ICC Staff Exhibit 6.0, p. 45)

Commission Analysis and Conclusion

Having reviewed the record of this proceeding, the Commission finds that Rider CLR 7, as modified in ComEd's surrebuttal testimony, is compatible with the procurement process approved in Docket 05-0159.The Commission finds it just and reasonable and Rider CLR 7 is hereby approved.

****189** *8. ELIMINATION OF RIDERS ISS, 26, 27, 30, 32*

ComEd

Consistent with the fact that ComEd no longer owns generation and must procure all of its energy through the wholesale market, ComEd proposes to consolidate its core demand response programs for non-residential customers into Rider VLR7 and Rider CLR7, which provide market-based incentives. Therefore, ComEd proposes to remove its current, and outdated, demand response Riders 13, 26, 27, 30, and 32 from its Schedule of Rates. ComEd indicates that proposed consolidation of these riders is necessary because Riders 13, 26, 27, 30, and 32 rely on incentives that are inconsistent with the PJM incentives for demand response. ComEd notes that proposed Riders VLR7 and CLR7 are market-based and essentially pass through the values from PJM, and can be made available to any qualifying non-residential customers, regardless of from whom they take their supply of electric power and energy.

Rider ISS provides supply services for up to approximately 90 days to customers that are dropped by their suppliers. ComEd voluntarily proposed Rider ISS as a transitional service, as part of ComEd's first delivery services rate case. However, Rider ISS, as currently designed, is no longer necessary or even appropriate in the post-transition period. Therefore, ComEd proposes to remove Rider ISS from its Schedule of Rates.

ComEd challenges IAWA's recommendation to retain Riders 13, 26, 27, 30, and 32 based on its claims that customers invested in standby generating equipment based on the current suite of riders, and that Rider

CLR7 may ***332** not cover the fuel cost to run standby equipment during a curtailment. ComEd averred that Rider CLR7 provides a market-based payment to customers who can commit specified amounts of firm demand response, regardless of whether or not a curtailment is ever called under the tariff. ComEd also pointes to Rider VLR7, a voluntary offering which compensates customers for every kilowatt-hour curtailed based on the PJM compensation structure, and for which there are no penalties for non-compliance as there are under Rider CLR7.

Staff

Staff does not object to ComEd's proposal to eliminate six riders. (ICC Staff Exhibit 6.0, pp.45-46) The riders ComEd proposes to eliminate are: Rider ISS - Interim Supply Service; Rider 13 - Governmental Pumping Service; Rider 26 - Interruptible Service; Rider 27 - Displacement of Self Generation; Rider 30 - Interruptible/ Curtailable Service; and Rider 32 - Curtailable Service Cooperative. Staff finds that the elimination of these services is consistent with ComEd's move toward energy procurement through an auction process. Moreover, maintaining these riders would be costly given the aforementioned change. (ICC Staff Exhibit 6.0, p. 45)

Commission Analysis and Conclusion

Although it did not file briefs in this proceeding, IAWC filed testimony recommending that Rider 13, 26, 27, 30 and 32 be retained because they are important demand response tools. The Commission believes that demand response is an important public policy issue. However, the record in this proceeding supports the elimination of the riders in question. Testimony from both ComEd and Staff demonstrated that these riders are no longer appropriate and that it is possible to implement effective demand response programs without these specific riders. ComEd's proposal to eliminate Rider 13, 26, 27, 30 and 32 is hereby approved.

****190** As for Rider ISS, the Commission finds that this interim supply service tariff is no longer necessary. ComEd's proposal to eliminate Rider ISS is therefore approved.

9. ELIMINATION OF RIDER 25

ComEd

[95] ComEd proposes eliminating Rider 25, demonstrating that it is an outdated tariff. Rider 25 provides a specific energy charge with no demand charges in the non-summer months for non-residential electric space heating load customers. It was created when ComEd was a vertically integrated utility, and contains a price structure that reflects the costs of a vertically integrated electric utility; specifically, the difference in ComEd's generation costs between summer and non-summer periods. Because ComEd no longer owns generation, a customer's end-use characteristics have no material effect on ComEd's cost to provide distribution service. Moreover, ComEd notes that the costs to provide distribution service to non-residential space heat customers are no different than other non-residential customers. ComEd articulates that Rider 25 is no longer cost-based, and its continuance would provide an improper subsidy to certain customers.

ComEd decries BOMA's proposal that customers with electric space heat meters be exempted from DFCs for eight months of the year, as unreasonable and devoid of any cost-justification. ComEd points out that exempting customers from legitimate demand charges sends an inappropriate price signal concerning the costs of distribution capacity, and creates a $48.9 million subsidy that other non-residential customers would have to fund. Moreover, ComEd indicates that non-residential space heating customers commonly have demands in the non-summer months that are at a similar level to their demands in the summer months. (*Id.* at 39:879-81). ComEd further notes that BOMA's complaints regarding the insufficiency of the Commission-approved bill impacts mitigation proposal in the Procurement Case do not belong in this Docket.

BOMA

***333** BOMA proposes that ComEd continue its practice of exempting nonresidential space heating consumers from demand charges on electricity used for space heating (in Rider 25) in the delivery services tariffs adopted by the Commission in this proceeding. (BOMA Ex. 1.0, pg. 11, ll. 237-241, BOMA Ex. 2.0, pg. 11, ll. 239-242). BOMA witnesses Messrs. Brookover and Childress testified that BOMA's nonresidential space heating proposal is designed to continue the separate rate treatment for these consumers that was begun nearly three decades ago when Rider 25 was first instituted. (BOMA Ex. 1.0, pg. 11, ll. 243-245). Messrs. Brookover and Childress testified also that ComEd's proposed elimination of separate rate treatment for nonresidential space heating consumers would cause massive rate shock for these consumers because they currently are charged approximately 17% less under Rider 25 than they would be under ComEd's otherwise applicable charges. (BOMA Ex. 1.0, pg. 8, ll. 164-174, pg. 10, ll. 207-213; BOMA Ex. 1.1; BOMA Ex. 1.2).

****191** In response to ComEd's argument that separate rate treatment for nonresidential space heating consumers is no longer necessary to promote the local use of nuclear and large coal baseload power to support operational efficiency, BOMA witness McClanahan testified that operational efficiency of the electric system in ComEd's service territory is still improved by promoting the use of nuclear and coal baseload plants at off-peak times. (BOMA Ex. 4.0, pp. 4-5, ll. 98-113). Mr. McClanahan, however, contended that ComEd may not want to promote such operational efficiency so that its affiliate company Exelon Generation can sell more electricity from its generating plants in high cost electric markets rather than in Illinois. (BOMA Ex. 4.0, pp. 4-5, ll. 98-113). Additionally, Mr. McClanahan pointed out that ComEd has not provided any cost basis for the elimination of separate rate treatment for nonresidential space heating customers. (BOMA Ex. 4.0, pg. 2, ll. 47-55).

In support of its proposal, BOMA notes that it represents both nonresidential space heating consumers and nonresidential non-space heating consumers in this proceeding and that it is in a vastly superior position to ComEd to determine whether BOMA's proposal is equitable to both nonresidential space heating consumers and nonresidential non-space heating consumers and is necessary to avoid massive rate shock. (BOMA In. Br., pg. 17). BOMA witnesses Brookover and Childress testified that the adoption of their proposal would make the overall rate increase for nonresidential space heating consumers comparable to the overall rate increase for nonresidential non-space heating consumers. (BOMA Ex. 3.0, pg. 4, ll. 76-84).

BOMA argues also that Staff's mitigation plan in ComEd's procurement case (Ill. C.C. Docket No. 05-0159) does not adequately address the massive rate shock which nonresidential space heating consumers would experience as a result of the elimination of Rider 25. (BOMA Ex. 4.0, pp. 6-7, ll. 127-138; BOMA In. Br., pg. 17.). BOMA witnesses Messrs. Brookover and Childress testified that the Staff rate increase mitigation plan only applies to nonresidential space heating consumers with less than 400 kW of peak demand and that 79% of the total nonresidential space heating load is ineligible for this rate mitigation plan. (BOMA Ex. 4.0, pp. 6-7, ll. 127-138). BOMA also points out that even for those nonresidential space heating consumers for whom the Staff mitigation plan does apply, the threshold for rate mitigation is extraordinarily high (*i.e.*, 20% or 150% of the average class rate increase, whichever is *greater*). (BOMA Ex. 3.0, pg. 7, ll. 145-147).

Commission Analysis and Conclusion

ComEd has proposed to eliminate Rider 25. BOMA proposes that ComEd continue exempting nonresidential space heating consumers from demand charges on electricity used for space heating. BOMA suggests such an outcome is necessary to avoid rate shock. ComEd, however, argues that BOMA's proposal would provide space heat customers with free delivery service for eight months each year.

****192** BOMA argues that under ComEd's current ***334** Rider 25, electricity used by a nonresidential space heating consumer in non-summer months for any other purpose (*e.g.*, lighting, elevators, computers, etc.) would not be exempted from demand charges. It is BOMA's position that operational efficiency of the electric system in ComEd's service territory is improved by promoting the use of nuclear and coal base load plants at off-peak times.

According to ComEd, Rider 25 reflected the difference in ComEd's generation costs between summer and nonsummer periods. ComEd states that now, it no longer owns generation and, therefore, a customer's end-use characteristics have no material effect on ComEd's cost to provide service. ComEd argues that what BOMA raises is a supply issue and not a distribution cost issue. The Company argues that the end-use characteristics and load shape of customers do not contribute to ComEd's distribution costs to any significant degree.

The Commission has reviewed the record and as a preliminary matter observes that this is a very difficult issue. It appears that over a period of many years, the Commission inadvertently allowed rates to be developed that are not reflective of cost causation. That is, it appears through Rider 25 nonresidential space heat customers were granted a discount on both the generation and delivery components of their demand charges. While the discount on generation demand charge was probably justified, the discount on the delivery component was not. Nevertheless, it made little difference until 1997 when restructuring of the Illinois electric markets began.

It is clear to the Commission that purely on the basis of cost; a discount in the distribution facilities charge to nonresidential space heat customers is not justified. The Commission believes it is appropriate to deviate from cost based rate design only in those instances where there is a significant overriding public policy consideration.

While the Commission is sympathetic to nonresidential space heat customers, it does not believe there is sufficient reason to deviate from cost based rate design here. ComEd correctly points out that the underlying issue BOMA raised here is related primarily to the cost of procurement or supply, not the cost of delivery.

BOMA has not suggested that if its proposal was adopted, customers could or would change their consumption behavior, either through conservation or load shifting. The Commission does not believe it would be appropriate to provide nonresidential space heat customers a delivery discount when such a discount would have no positive impact on future actions taken by those customers.

The Commission next turns to the rate shock and rate mitigation issues raised by BOMA. In Docket 05-0159, BOMA proposed to exempt non-residential space heat customers from demand charges associated with delivery. The Commission correctly found that such a question should not be decided in that proceeding.

****193** In this proceeding, BOMA's assertions about possible rate impacts rely directly upon its assumptions regarding future procurement costs. That is, BOMA's request for a discount on delivery service charges due to alleged rate shock is premised upon its anticipated increase in both delivery services and supply services. While the Commission understands BOMA's concerns, it does not believe there are sufficient reasons to deviate from cost based rates in this instance.

The Commission would expect that to the extent nonresidential space heat customers provide benefits to generation suppliers, such customers would be attractive to alternative suppliers. While the Commission is not unsympathetic to BOMA, all things considered the Commission believes there are insufficient public policy considerations that warrant deviating from cost based delivery demand rates (distribution facilities charges) for nonresidential space heat customers.

10. RIDER DE

ComEd

ComEd proposed Rider DE - Distribution System Extensions to replace current Rider ***335** 2, with modifications and the inclusion of a formula to use in determining the cost of an extension to the distribution system.

ComEd indicated that it fully clarified any confusion with respect to its application, a concern expressed by the CTA.

Staff

Staff does not object to ComEd's proposed Rider DE - Distribution System Extensions. (ICC Staff Exhibit 6.0, p. 53) Rider DE determines the charges an individual customer will pay ComEd to extend its distribution system to provide standard electric service to that customer. (Rider DE, ComEd Ex. 10.0, Sched. E2, ILL. C.C. No. 4, Orig. Sht. No. 434). Staff finds the rider to be reasonable. (ICC Staff Exhibit 6.0, p. 53)

Commission Analysis and Conclusion

ComEd proposes to replace Rider 2 with Rider DE relating to Distribution System Extensions. It appears that no party objects to ComEd's proposed Rider DE; the Commission finds ComEd's proposed Rider DE to be reasonable and it is hereby approved.

11. RIDER NS

a). Reserved Capacity Charge

ComEd

[96-98] ComEd argues that a reserved distribution system capacity charge is not new and that the proposed language in Rider NS clarifies that reservation of distribution system capacity is a non-standard service under ComEd's existing Rider 6 and under ComEd's proposed Rider NS. ComEd describes the change as providing clarification, and codification of, ComEd's existing practice.

ComEd indicates that, contrary to the CTA's claims, it is entitled to recover its costs associated with reservation of capacity, a position with which Staff agrees. ComEd notes that the CTA provided no persuasive evidence to support its position why it should receive this service - which benefits only the CTA - for free.

ComEd also indicates that, contrary to the CTA's assertions, reserve capacity distribution system capacity charges are not new. ComEd witnesses testified that the proposed language in Rider NS clarifies that reservation of distribution system capacity is a non-standard service under ComEd's existing Rider 6 and under ComEd's proposed Rider NS.*See* ComEd Ex. 10.14, page 3 of 5; Alongi/McInerney Sur., ComEd Ex. 41.0 Corr., at 23:527-30.

****194** ComEd also states that a set fee is not feasible under the proposed rider due to the project-specific nature of reservation of distribution capacity. According to ComEd, such enhanced service requests areas are relatively few in number and very project-specific based on the feeders in the specific geographic area in which the customer is located. Consequently, ComEd argues that the determination of costs and corresponding charges for such requests is appropriately computed to reflect the individual circumstances of each customer's situation. ComEd notes that Staff did not oppose this proposed case-by-case treatment of expenses in this rider.

Additionally, according to ComEd, the Ravenswood fire highlighted by the CTA demonstrates that reservation of capacity exists on ComEd's system. ComEd notes that the CTA fire that damaged both lines serving that CTA traction power station constituted a double contingency-not a single contingency. ComEd avers that the reservation of distribution system capacity allowed for power to be fully restored the next day through repair to a single ComEd line, while work continued for over a week on the second of the two damaged lines.

Staff

Staff no longer takes issue with ComEd's proposed Rider NS regarding language that would allow ComEd to charge costs in addition to those stated in the tariffed rates. In his direct testimony, Staff Witness Hanson identified language in ComEd's proposed Rider NS that was vague and confusing and that could allow ***336** ComEd to double charge for transmission and distribution capacity. (ICC Staff Exhibit 7.0, p. 9) In its rebuttal testimony, ComEd modified its language in proposed

Rider NS with respect to transmission capacity, ensuring that customers would not be double charged. (ComEd Ex. 24.0, pp. 21-11) Staff witness Hanson, in his rebuttal testimony, stated that the aforementioned changes to transmission capacity language and clarifications by ComEd with respect to distribution capacity satisfied his concerns. (ICC Staff Exhibit 18.0, p. 2)

CTA and Metra

The CTA and Metra vigorously oppose the proposal by ComEd to insert new language into Rider NS (the former Rider 6) that would allow ComEd for the first time to include a reserved distribution capacity charge that would affect the CTA and Metra. In essence, the reserved capacity charge is a fee that the CTA and Metra would have to pay to ‘reserve‘ distribution facilities on the ComEd system to serve the CTA and Metra loads.

The CTA and Metra receive power and energy at each of their traction power substations from ComEd via at least two 12,500 volt distribution lines. In the railroad's substations, the alternating current power is transformed into direct current power for the trains. By using at least two lines, power and energy flows into the CTA and Metra substations as well as through the substations and back out onto the ComEd distribution system. In effect, the CTA and Metra argue that they are providing a loop for ComEd, thereby enhancing the ComEd system as a whole. ComEd does not pay either the CTA or Metra for this enhanced service.

****195** The current Rider 6 does not have language to allow for a reserved distribution capacity charge. Staff Witness Hanson testified that ComEd could not charge for reserved distribution capacity under the current rider even though ComEd said it changed its policy to start charging the fee in 1997. To date, neither the CTA nor Metra has paid any reserved capacity charge assessed by ComEd for any traction power substation. The CTA and Metra oppose ComEd's proposed reserved capacity charge on several grounds.

CTA and Metra offer the following arguments in opposition to the reserved capacity charge in ComEd's proposed Rider NS: first, Rider NS has no charge, which is contrary to the Public Utilities Act; second, the cost for ‘reserving‘ capacity far exceeds the construction costs for similar facilities; third, as demonstrated by the CTA Ravenswood substation fire, ‘reserved capacity‘ is a myth; fourth, ComEd lacks the means to ensure that any fees collected from a reserve capacity charge are not double collected; and fifth, the contract that governs the relationship between the CTA and ComEd and the contract between Metra and ComEd, do not allow for a reserved capacity charge.

First, the CTA and Metra note that there is no rate associated with Rider NS for the reserved capacity charge but that ComEd would be allowed to determine the charge solely on its own with no review by the Commission. The CTA argues that this proposal is contrary to the Public Utilities Act, 220 ILCS 5/10-201, as explained in *Citizens Utility Board et al. v. Illinois Commerce Commission, 275 Ill.App.3d 329, 655 N.E.2d 961 (1st Dist. 1995).* According to the CTA, in *Citizens Utility Board*, the court found that the Act does not permit a utility to have a tariff that allows the utility to set its own rate in the future. Metra also argued that it is bad public policy, and neither fair nor appropriate, to give ComEd carte blanche to demand payment in advance before installing facilities with absolutely no limit or justification required relating to the amount demanded by ComEd.

Second, the CTA testified that in one instance, ComEd demanded construction costs of $109,869 for a distribution line to a CTA substation and then proposed CTA pay an additional reserved capacity charge of $1.2 million.

Third, the CTA presented unrebutted evidence that as a result of a fire at its Ravenswood traction power substation in February 2004, it was forced to operate commuter trains on a reduced schedule because the ‘reserved‘ capacity was not there. ComEd stated at hearing that ***337** ‘reserved‘ capacity is available for only 24 hours. According to the CTA, that is why, ComEd testified, that the CTA could not operate the Ravenswood substation through the summer months with only one service line.

Fourth, the CTA argues that the reserved capacity charge is being collected on existing distribution facilities of ComEd-facilities that are already in the rate base. The CTA and Metra point out that ComEd does not know how many customers paid a reserved capacity charge in the test year nor did ComEd know how much money was collected from customers. Thus, the CTA argues, ComEd could double collect for facilities through the reserved capacity charge.

****196** Fifth, the CTA and Metra point out that under their current contracts with ComEd there is no provision for the CTA or Metra to pay a reserved capacity charge. As discussed more fully below, the CTA and Metra contend that their contracts with ComEd govern whether or not ComEd can assess a reserved capacity charge. The CTA's and Metra's positions are that since their contracts, as amended, do not provide for a reserved capacity charge, the Commission cannot impose a reserved capacity charge on the CTA or Metra. To do so, the CTA and Metra contend, would violate the U.S. Constitution Art. I, Sec. 10 and the Illinois Constitution Art. 1, par. 16 as well as the Public Utilities Act, 220 ILCS 5/16-129.

b.) Standard Service Construction Costs

CTA and Metra

ComEd serves the CTA traction power substations by providing two 12,500 volt distribution lines connected at a bus in the CTA substation. The CTA is engaged in a major renovation and line construction program. In the past, ComEd has built and paid for both service lines to the CTA substations. As a result of the 1998 amendment to the CTA/ComEd contract, ComEd agreed to pay for the construction of one of the service lines as ‘standard service‘ and the CTA would pay for the construction costs for the second line.

CTA argues that ComEd's testimony has created a ‘hypothetical‘ system under which the CTA takes all power and energy from ComEd at one location where there are three 50 MVA transformers. According to CTA, until the capacity for the ‘hypothetical‘ substation is exceeded, the CTA must pay for all service lines to the CTA substations.

The CTA argues that the contract between the CTA and ComEd governs how construction costs are to be allocated between the two parties. ComEd has offered no explanation as to why the contract provisions should be overwritten by ComEd in this proceeding.

CTA and Metra argue that ComEd, at the eleventh hour, attempted to inject a new proposal in this Docket regarding the customers in the Railroad Class. In its surrebuttal testimony, ComEd requested that the Commission abolish the Railroad Class and that, as a ‘compromise,‘ ComEd would agree to pay the construction costs for the first line to service the CTA and Metra at each substation. Both customers reject the proposal and indicate in their briefs that such proposals would end up costing them more since they would no longer be over 10 MW and their rates would increase substantially.

c.) Effect on Existing Contracts

ComEd

See discussion of BES-RR in Section VIII.20 of this Order, *infra*.

CTA and Metra

The CTA and Metra dispute the unilateral changes to existing contracts that ComEd proposes. For example, the CTA and Metra object to ComEd's insertion of a ‘reserved capacity‘ charge into the contract and the changing of who is to pay for the construction of service lines to the traction power substations.

The original contract between the CTA and ComEd was signed in 1958. It was amended in 1998. The original Metra contract was executed in 1986 and, except for rate changes, has never been substantially amended. The CTA and Metra argue that this Docket is not the proper ***338** venue for ComEd to make unilateral and significant changes to the agreements and the relationship between the parties. For over 50 years, and 30 years, respectively, the parties have negotiated changes, and then filed those changes with the Commission. The CTA and Metra note that under the Electric Service Customer Choice and Rate Relief Law of 1997, the Commission is prohibited from changing existing contracts. 220 ILCS 5/16-129.

****197** The CTA and Metra point to the prohibition in the U.S. Constitution, art. I, Sec. 10, which provides that no State shall make any law impairing the obligation of contracts. A similar provision is found in the Illinois Constitution at art. I, par. 16. The CTA and Metra cite to *Royal Liquor Mart, Inc. v. City of Rockford,* 113 Ill.App.3d 868, 479 N.E.2d 485 (2nd Dist. 1985) as standing for the proposition that this Commission should not interfere with the CTA-ComEd contract. Rather, the CTA and Metra contend, the Commission should leave it to the parties to determine what contract changes would be made.

d.) Rider NS and Elimination of Rider 8

ComEd

ComEd proposes that the current Rider 8 should be eliminated. As described by ComEd, this seldom-used rider provides a small credit (20.533[/kW) to approximately 225 current customers (less than 35 have installed their own transformer and utilized Rider 8 over the past 10 years) who have installed their own transformers. ComEd proposes to provide a standard transformer allowance under Rider NS to replace the Rider 8 credit, which ComEd indicated would likely result in lower Rider NS monthly rental charges for many of the current Rider 8 customers.

In response to Staff's recommendation, ComEd states that it is agreeable to provide a one-time transition payment to each Rider 8 customer in an amount that is equivalent to one year of Rider 8 credits, based on the customer's average Rider 8 credits received over the most recent three year period.

Staff

Staff opposes the termination of Rider 8 but does not oppose ComEd's alternative position if Rider 8 is not terminated. If the Commission decides that ComEd should be allowed to terminate Rider 8, Staff recommends that ComEd and the customer agree upon a payment for termination, rather than ComEd's offer of a ‘one-time, one-year equivalent transition payment.‘ (ComEd. Ex. 24.0, p. 27) A negotiated transition payment allows the current customer to agree upon a reasonable payment from ComEd in exchange for terminating that customer's service under Rider 8.

ComEd Proposal

ComEd's primary proposal is to discontinue Rider 8 and provide a one-time transition payment to each existing Rider 8 customer as of the date of the order in this case. ComEd proposes that it will pay each Customer a transition payment equal to one year of credits that the customer would be entitled to receive under Rider 8. (ComEd. Exhibit 24.0, pp. 26-27) It is Staff's reading of ComEd's surrebuttal testimony that in the event the Commission does not eliminate Rider 8, ComEd proposes that the availability of Rider 8 be limited to only the existing Rider 8 customers, and that no new customers be allowed to take service under Rider 8. (ComEd Ex. 41.0, pp. 18-19) In the event Rider 8 is not eliminated, ComEd also requests that the Rider 8 credits be included in the revenue requirements. (ComEd Exhibit 24.0, pp. 26-27)

Staff Opposition to ComEd's Primary Proposal

****198** Staff opposes the proposals offered by ComEd. ComEd's primary proposal is to discontinue Rider 8 and provide a one-time transition payment to each existing Rider 8 customer as of the date of the order in this case. Staff argues that customers who purchased transformers based on the expectation of being compensated for that cost through Rider 8 will no longer receive compensation. In addition, this ***339** proposal would result in an increase in the electric bills of most of the 225 Rider 8 customers. (ICC Staff Exhibit 8.0, pp. 12-13)

Staff explains that the one time compensation ComEd is offering, which is equal to one year's worth of credits, is insufficient when compared to the amount the customer spent on the purchase of a transformer. A transformer's life expectancy is thirty years. Some of the Rider 8 customers have installed transformers within the last ten years. Staff asserts that a one-time payment equal to one year's worth of credit would not approach the total amount of credit a customer expected to receive over the life of that transformer when it purchased the transformer. (ICC Staff Exhibit 19.0, pp. 6-7) According to Staff, ComEd's proposal amounts to a rules change in the middle of a game - which is both unfair and unreasonable.

In the event the Commission decides to allow ComEd to terminate Rider 8, Staff recommends that the Commission reject ComEd's proposed termination payment of a ‘one-time, one-year equivalent transition payment.‘ (ComEd. Ex. 24.0, p. 27) In place of ComEd's proposal, Staff recommends that ComEd and the customer negotiate a compensation amount to the customer for terminating the provision of Rider 8. (ICC Staff Exhibit 19.0, pp. 6 and 8) The purpose of the negotiated transition payment is to allow the current customer to agree upon an amount which they view to be a reasonable compensation for the value and expected life of the transformer, or transformers, the customer had purchased. (*Id.* at 6-7)

Staff proposed language to be inserted into Rider 8, if ComEd is allowed to terminate Rider 8, and Staff's proposal for a negotiated transition payment is accepted.

ComEd's Alternative Proposal

Staff explained that it does not oppose ComEd's alternative proposal (*i.e.*, in the event that Rider 8 is not eliminated by the Commission), because Staff understands this proposal to allow all customers from Rider 8 to continue receiving Rider 8 credits and will allow the customer to determine if and when they should stop taking of Rider 8. (ComEd Exhibit. 41.0, pp. 18-19)

Commission Analysis and Conclusion

ComEd proposes to replace Rider 6 with Rider NS which allows it to recover its costs for providing non-standard services and facilities. With respect to the reserved distribution system capacity charge, ComEd states that the most common example of such a non-standard service requirement is a customer's request for a service arrangement that included automatic switching to an alternate feeder. ComEd claims its reserved distribution system capacity charge is not new and the proposed language in Rider NS clarifies that reservation of distribution system capacity is a non-standard service under ComEd's existing Rider 6 and under ComEd's proposed Rider NS.

****199** The charge for reserved distribution system capacity is intended to recover the cost from the cost-causer of distribution system capacity that is reserved to accommodate the automatic transfer of a customer's load from one ComEd line to another. ComEd's costs associated with providing this non-standard service should be recovered from the cost-causer. Staff initially raised a concern regarding the proposed language in Rider NS for the reserved distribution system capacity. However, ComEd adequately addressed Staff's concern in rebuttal testimony and Staff no longer takes issue with Rider NS. Staff witness Hanson agreed that ‘ComEd is certainly entitled to recover its costs for such capacity.‘ Hanson Dir., Staff Ex. 7.0, at 9:192.

It is CTA's position that ComEd's proposed language in Rider NS has the same fatal flaws as Rate CS had in the *Citizens Utility Board et.al. v. Illinois Commerce Commission, 275 Ill. App. 3rd 329, 655 N.E. 2nd 961 (1st District 1995) case*.The CTA says there is no rate in the rider and ComEd has the sole discretion to determine what it will charge the customer. The final rate is not even filed with the Commission and the customer has no recourse but to pay the charge. Metra concurs with CTA in this regard.

***340** ComEd asserts that in the *Citizens Utility Board case*, the Court confined its holding to base rates and did not address an analysis of a rider mechanism used to account for unexpected, volatile, or fluctuating expenses. ComEd claims the present case is not one where ComEd seeks a prospective right to set rates in the future for an entire category of customers by negotiating a rate to best give the utility a competitive advantage. ComEd argues that, instead, it is proposing to use a rider mechanism to ensure its ability to recover a unique cost that is inherently variable, *i.e.*, the cost of providing reserved capacity.

Metra and the CTA assert that the facilities being reserved are not actually physically reserved. This claim is disputed by ComEd.

It is the CTA's position that the Commission should not allow ComEd to unilaterally rewrite a contract and not even allow the other party to the contract to negotiate or even to know what language is being changed. The CTA argues this would be the result if Rider NS were approved.

The Commission has reviewed the record and is sympathetic to CTA's concerns with the reserved capacity language in ComEd's proposed Rider NS. Although ComEd claims that the reserve capacity charge arose in 1997 when it modified the methodology for charging customers that request automatic throw over equipment, Rider 6 clearly does not allow ComEd to assess reserved capacity charges to retail customers. (Tr. at 1376; see also Rider 6) Further, ComEd could not identify any customers that have ever been charged for reserve capacity. (*id.*)

The Commission finds the language related to reserved capacity in ComEd's proposed Rider NS problematic. ComEd failed to adequately explain the exact nature of the service it would provide when it sells reserve capacity to retail customers. Reserved capacity is a term that is commonly associated with open access to pipelines and transmission lines in wholesale natural gas and electricity markets. In general, suppliers purchase reserved capacity on pipelines and transmission lines to ensure delivery of commodity to the local distribution utility where the commodity is then delivered to the retail customer. At the distribution level, retail customers, such as the customers served by ComEd, pay for their share of capacity on the distribution system through non-bypassable delivery service charges, which are at issue in the instant proceeding. The Commission is concerned that the reserved capacity charge language in ComEd's proposed Rider NS would permit ComEd to charge what, in effect, would amount to additional delivery service charges that are not approved by the Commission. The Commission rejects the language in ComEd's proposed Rider NS related to reserved capacity charges and finds that the remaining provisions are adequate for ComEd to recover the cost of additional facilities necessary to provide non-standard service.

****200** With respect to the CTA proposal that ComEd be required to state specific charges in Rider NS, ComEd argues that it is not necessary for Rider NS to contain explicit rates and charges because it is proposing to use a rider mechanism to ensure its ability to recover a unique cost that is inherently variable. What ComEd's proposal does not include, however, is that Rider NS will be subject to an annual accounting reconciliation and prudence review like most riders that contain formulae rather than actual rates and charges. The Commission notes that ComEd has several riders in place that are not intended to recover unique or inherently variable costs. Rider 7 (Meter Lease), is just one example of a rider that contains explicit rates and charges.

The Commission is not willing to authorize ComEd to assess charges with essentially no regulatory oversight. Accordingly, the Commission directs ComEd in its compliance tariff filing to incorporate the modifications proposed in its rebuttal testimony to address Staff's concern and incorporate a formula to determine the cost of providing non-standard services and facilities. Such formula shall be modeled after the formula as provided in Rider DE (on Sheet 436) that ComEd developed in cooperation with the Commission Staff as agreed in Docket 03-0767 for use in determining the cost of furnishing a distribution system extension.

***341** ComEd also proposes to eliminate Rider 8 and provide a standard transformer allowance under Rider NS to replace the Rider 8 credit. Staff expressed concern that this proposal would raise the cost to some Rider 8 customers and opposes the elimination of Rider 8. Staff recommends that Rider 8 not be eliminated, or as an alternative, that Rider 8 customers be allowed to negotiate a termination payment. The termination payment would allow the customer to be able to agree upon an amount that would adequately compensate it for the costs it incurred in having to purchase a transformer. In response, ComEd proposes an alternative to the position it put forth in its direct testimony, proposing to continue Rider 8 and provide those customers who want to terminate Rider 8 with a one-time transition payment in an amount equivalent to one year of Rider 8 credits. This would be based on the customer's average Rider 8 credits received over the most recent three-year period. Staff argues that any one-time credit should be negotiated between ComEd and each Rider 8 customer, since it is unclear whether such a credit would adequately compensate Rider 8 customers for the cost of their transformer. ComEd objects to negotiating a one-time credit with customers and instead would prefer to allow existing customers to be grandfathered under Rider 8 and allow ComEd to make a corresponding adjustment to its rate design to provide an offset for such continued credits to allow ComEd to recover its revenue requirement.

Having reviewed the record as well as the arguments on this issue, the Commission concludes that it would be best to retain Rider 8 without modification. We find that ComEd has not provided sufficient reason for us to terminate Rider 8. In addition, we do not see the termination of Rider 8 to be appropriate given that approximately 140 of the 225 customers would no longer recover the money they invested in the purchase of one or more transformers. Rider 8 customers purchased transformers with the expectation that Rider 8 credit would compensate them for their cost of purchase. To leave those customers without adequate compensation causes a harm that is not justified at this time.

12. RIDER POG

ComEd

****201 [99-101]** ComEd proposes to replace its current Rider 4 - Parallel Operation of Customer's Generating Facilities (‘Rider 4‘) with Rider POG - Parallel Operation of Retail Customer Generating Facilities (‘Rider POG ‘). Rider POG differs from Rider 4 in that it utilizes hourly spot prices from PJM to determine ComEd's avoided energy costs. As explained by ComEd, ComEd then uses this cost information to develop its standard energy payment to certain electricity generating facilities, known as Qualifying Facilities (‘QFs ‘) under Section 210 of the Public Utilities Regulatory Policies Act of 1978, 16 U.S.C. § 824a-3.

ComEd indicates that Staff's position is problematic for various reasons. First, according to ComEd, Staff's recommendation is not consistent with the Commission's decision in the Procurement Case. ComEd witness Crumrine testified that adoption of an annual fixed avoided energy cost would conflict with the intricate decisions made as part of the Procurement Case that dictate which load is displaced by QF operation, depending on the QF's size. ComEd claims that a result of the Commission's Procurement Case Order is that ComEd's avoided energy costs are the PJM spot market prices. According to ComEd Staff's witness agreed on cross-examination that ComEd's method to determine avoided costs under Rider POG was reasonable.

Moreover, ComEd contends that setting an annual fixed avoided energy cost would jeopardize ComEd's full cost recovery. ComEd argues that, on cross-examination, Staff's witness admitted as much. Simply stated, Staff's recommendation requires ComEd or Staff to accurately predict ComEd's avoided energy costs or PJM spot market prices. ComEd claims that this is unreasonable and could result in a situation where ComEd is penalized for guessing incorrectly.

ComEd articulates that, in contrast to Staff's proposal, its own proposal to utilize spot market-based purchase rate will send the appropriate***342** price signals to QFs. According to ComEd, spot market prices would create a clear incentive for QFs to manage their output and generate electricity at times when there is a scarcity of supply - that is, when prices are high. On the other hand, a fixed annual purchase rate, with seasonal and/or time-of-day differentiation, would send a price signal that is muted by the averaging that normally occurs in such calculations. This would not give QFs the maximum incentive to actually be on the system and generate at the times of highest market prices.

In addition, ComEd claims that the Commission already has determined that the appropriate price that ComEd should offer to retail customers that utilize self-generation is an hourly price based on the PJM spot price. According to ComEd, there is no reason that qualifying facilities taking service under Rider POG should receive a price signal any different than that which the Commission has already determined to be appropriate for self-generating customers.

ComEd comments that during the cross-examination of ComEd witness Crumrine, Staff inquired whether ComEd was amenable to the addition of language to the compensation section of proposed Rider POG. The following language, shown in legislative style, was proposed in ComEd Ex. 49.0:

****202** Unless the customer negotiates a different compensation arrangement with the Company pursuant to 83 Illinois Administrative Code Part 430, for a retail customer taking service under Option C or Option D, the Company compensates the retail customer for output from such retail customer's electric generating facility that is sold to the Company.

ComEd indicated that it is amenable to this modification to Rider POG. However, it was not clear to ComEd whether Staff supported this language as an alternative to ComEd's proposal.

Staff

Staff opposes ComEd's proposal to implement Rider POG - Parallel Operation of Retail Customer Generating Facilities and eliminate the current Rider 4, but will withdraw its opposition if ComEd agrees to two additions. Staff also points out that there is a tangential federal reporting issue, which Staff is not addressing at this time, but will address when ComEd makes its annual filing of avoided costs, in compliance with 83 Illinois Administrative Code Part 430 and furtherance of 18 CFR §292(d).

Staff provides the following background information. Through the Public Utility Regulatory Policies Act of 1978 ('PURPA'), Congress encourages cogeneration and small power plant production. Federal rules implementing PURPA require an electric utility to purchase energy and capacity made available by a qualifying facility [FN31] ('QF'). (18 CFR §292.303(a)) The rates and terms of the purchases from the QF must comply with Section 292, or can be negotiated by the electric utility and QF. (18 CFR §292.301) According to Staff, the issue at hand relates to the former.

Staff avers that the rate of compensation to the QF must comply with Section 292.304. Staff states that Section 292.304 makes clear that one of the factors affecting rates for purchases is avoided costs. (18 CFR §292.304(e)) An electric utility is to provide to the state regulatory authority 'the estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. ' (18 CFR §292.302(b)(1)) The provision of the avoided cost data to the Commission is facilitated through Section 430.50 of the Commission's rules. (83 Ill. Admin. Code §430.50)Section 430.50 directs Illinois electric utilities to file the information described in Section 292.302(b) 'not less than every two years' in June. (ICC Staff Exhibit 8.0, p. 8; *see also* ComEd Ex. 9.0, pp. 2627; ComEd Ex. 40.0, pp.76-77)

The current rider under which ComEd compensates QFs is Rider 4. The compensation, or rates, set forth in Rider 4 are for a one year period. (Rider 4, ComEd Ex. 10.1, ILL. C.C. No. 4, 4th Rev. Sht. No. 64.10). ComEd has been annually updating the customer compensation in Rider 4, to coincide with any annual changes in avoided costs. (ICC Staff Exhibit 8.0, p. 12)

***343** In this tariff filing, ComEd proposes to replace existing Rider 4 with Rider POG. (ComEd Ex. 9.0 Corrected, pp. 26-27; ComEd Ex. 10.14, p. 4) Both Rider 4 and Rider POG include terms and conditions for ComEd's purchase of excess electricity generated by a QF, or customer. Rider POG describes four services under which ComEd would purchase excess electricity (Options A - D), and only under Options C and D is the QF compensated. (Rider POG, ComEd Ex. 10.1, ILL. C.C. No. 4, Orig. Sht. No. 458-59) According to Staff, a QF is compensated either through Nodal Compensation or Zonal Compensation. (*Id.* at Sht. No. 459) Staff notes that both methods of compensation have replaced the express rate per kW-hour, that is based on avoided costs, with a formula that is based on the PJM Real Time Generator nodal Locational Marginal Prices (‘LMP‘) or PJM real-time, LMP for the ComEd zone (‘PJM data‘).

****203** Staff's concern is that ComEd intends to no longer state a specific amount of compensation, or rate, in its new rider. (ICC Staff Exhibit 19.0, pp. 2-5) The current rider - Rider 4 - expressly states the rate at which a QF will be compensated for selling its excess electricity to ComEd, whereas, in contrast, Rider POG only describes the factors it would use to calculate the rate ComEd would pay the QF.

Staff argues that Rider POG should expressly state the rate ComEd would pay a QF. Staff recommends two modifications to Rider POG. First, Staff recommends that language be added to Rider POG recognizing that Part 430 grants QFs the ability to negotiate electric rates or capacity rates. This language is reflected in ComEd Exhibit 49.0, which was filed post-hearing. Staff states that it has no objection to the additional language that is reflected in Exhibit 49.0. Thus, the only issue regarding Rider POG is Staff's second proposal, which is that Rider POG should offer an additional standard rate for Options C and D; rates that expressly state the rate at which ComEd would compensate the QF.

Staff still contends that the failure to openly state a level of compensation in Rider POG adds uncertainty to the market, and that uncertainty is contrary to Congress' intention to conserve energy by using the excess electricity generated by independent generating facilities. (ICC Staff Exhibit 19.0, p. 3) Staff posits that certainty can be provided by adopting its position.

Staff explains that the intent behind PURPA was to encourage cogeneration and small plant power production. For that intent, Staff relies upon a FERC Notice of Proposed Rulemaking, issued at the time FERC was initiating its rules governing QFs, in which the FERC stated ‘Section 210(a) [of PURPA] requires the [FERC] to prescribe rules 'as it determines necessary *to encourage cogeneration and small power production* …which rules [shall] require electric utilities to offer to sell electric energy to and purchase electric energy from qualifying cogeneration and small power production facilities,’ ‘ and ‘that section 210(a) of PURPA 'provides a general mandate for the [FERC] to *prescribe rules necessary to encourage cogeneration and small power production* (emphasis added).’‘ (*Eligibility, Rates and Exemptions for Qualifying and Utility-Owned Geothermal Small Power Production Facilities* ; Notice of Proposed Rulemaking, Docket No. RM 81-2, 45 FR 74934 (Nov. 13, 1980)) Staff asserts that the lack of a definite rate of compensation to the QF in Rider POG is not consistent with Congressional intent.

Staff witness Linkenback also explains that the compensation described in Rider POG does not provide sufficient incentive for small generators or co-generators to become a QF or for existing QFs to continue selling their excess generation. (ICC Staff Exhibit 19.0, p. 4) Potential small power producers will likely be discouraged by the absence of a definite rate in proposed Rider POG and decide not to make the investment in generating equipment, which in turn would reduce the number of small power producers who choose to operate in ComEd's service territory. (*Id.*) Staff therefore argues QFs and potential QFs need to know what the compensation rates will be so they can determine their potential return and risk, and that this lack of information increases uncertainty in this area of power generation and deters companies from ***344** becoming a co-generator or a small power producer. Staff proposes that language paralleling the fixed price offering in Rider 4 (ComEd. Exhibit 10.1, ILL. C.C. No. 4, 30th Revised Sheet No. 64) be inserted into Rider POG.

****204** In the event that the Commission adopts Staff's position, and requires ComEd to expressly state a rate of compensation as an alternative to the Nodal and Zonal Compensations, Staff explains that such rate of compensation would still be tied to the avoided costs in ComEd's Part 430 filing. In June, ComEd is to submit avoided cost information in compliance with Part 430. Staff explains that, traditionally, ComEd changes the rate of compensation in Rider 4 based on that information. (ICC Staff Exhibit 8.0, p. 12) Rider 4 is to remain in place until Rider POG starts on January 2, 2007.

(ICC Staff Exhibit 8.0, p. 7, lines 145-150)

Thus, Staff recommends that the rate of compensation that will be stated in Rider 4, for the second half of 2006, be transferred into Rider POG. Staff argues that this would make sense, since Staff is proposing to include in Rider POG the same compensation language that is in Rider 4. On a going forward basis, Staff proffers, Rider POG can be updated annually based on its Part 430 filing, similar to Rider 4.

In its initial brief, Staff points out that the approval of Rider POG should not be considered a review and approval of an alternative method of estimating avoided cost data as prescribed in 18 CFR §292.302(d). Staff explains that Federal Rules require a state commission to notify the FERC if the data used to estimate avoided costs is different than what is prescribed by Section 292.302(b)(1). (18 CFR §292.302(d)(2)) Section 292.302(d)(1) states:

After public notice in the area served by the electric utility, and after opportunity for public comment, any State regulatory authority may require (with respect to any electric utility over which it has ratemaking authority), or any non-regulated electric may provide, data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data.

(18 CFR §292.302(d)(1)) (emphasis added). Staff interprets ‘data‘ in the preceding quote, as the same information Illinois electric utilities provide the Commission in June pursuant to Section 430.50. This is cost data has been used by ComEd to determine the compensation to QFs and which ComEd seeks to change in Rider POG. (ICC Staff Exhibit 8.0, p. 9) Therefore, Staff is anticipating that ComEd will be changing its method of calculating future avoided energy costs in its annual Part 430 filing, although Staff cannot be sure what method ComEd will use until ComEd submits that filing. (§430.50(a)(1)(B)(i)) Thus, Staff argues that the issue is not ripe at this time, since ComEd has not formally explained how it will be calculating its avoided costs in compliance with Part 430. Moreover, ComEd did not request that this proceeding address this federal notification requirement. Thus, Staff recommends that the Commission expressly state in the order that approval of Rider POG does not constitute review and approval of an alternative method of estimating avoided cost data as prescribed under federal law.*Commission Analysis and Conclusion*

****205** ComEd proposes to replace Rider 4, Parallel Operation of Customer's Generating Facilities, with Rider POG. Staff avers that the issue is not yet ripe. Staff also objects to Rider POG and, among other things, insists that an annual fixed avoided energy cost rate is needed to promote small power producer production in Illinois. Under Rider POG, ComEd's avoided energy costs would be the PJM spot prices. ComEd argues that this issue was essentially decided in Docket 05-0159 and that requiring an annual fixed avoided energy cost rate would jeopardize ComEd's full cost recovery. The Commission disagrees with ComEd that the issue was essentially decided in Docket 05-0159. While the tariffs approved in the order in that docket specify that purchases from QFs will offset power purchased from suppliers in the hourly auction, the Commission made no finding related to the price that ComEd would be required to offer to QFs in order to fulfill the requirements of Ill. Code Part 430.

***345** Staff argues that Rider POG, unlike Rider 4, does not clearly identify how much a QF will be compensated for the excess electricity they generate and sell to ComEd. This lack of information, Staff argues, could cause co-generators or small generators who are QFs to stop selling excess electricity, or influence those that are not yet a QF to not become one. Staff argues that the lack of an expressly stated avoided cost rate could provide instability in the QF market. Staff further argues that such instability is contrary to federal law, under the Public Utility Regulatory Policy Act of 1978 (PURPA), which promotes the use of QFs. To resolve this problem, Staff recommends that Rider POG provide an expressly stated compensation level per kW-hr in dollars and cents. These rates should be an alternative to the Nodal and Zonal Compensations currently in Rider POG.

All things considered, the Commission finds Staff's proposal to be just and reasonable. In addition, the Commission finds merit in providing the market-based price signals proposed by ComEd as an additional option to the expressly stated rate proposed by Staff. ComEd's proposed Rider POG shall be modified to include Staff's proposal with PJM spot prices as an alternative option to an expressly stated rate. The expressly stated rate shall be updated annually in the same manner that Rider 4 is updated.

13. RIDER GCB7

ComEd

[102] ComEd proposes to replace its current Rider GCB with Rider GCB 7 - Governmental Consolidated Billing 2007 ('Rider GCB7'). Rider GCB7 would allow certain governmental customers to consolidate their billings by selecting a single day each month as the due date for payment of bills. Rider GCB7 does not contain provisions establishing separate demand charges for these customers, based on maximum and coincident demand of the governmental accounts. Rather, the proposed rider applies the charges under the BES tariffs applicable to these accounts, respectively.

ComEd states that consolidated billing of this type is required by the Act.*See* 220 ILCS 5/16-125A. ComEd indicates that its proposal meets this requirement. ComEd notes that Rider GCB7 is also required because of changes arising from the Procurement Case. Specifically, according to ComEd, because the cost of capacity is embedded in the auction clearing price for full requirements electric supply, Rider GCB7 removes the demand charge provisions from Rider GCB to avoid imposing such costs on these customers twice. Thus, ComEd states that Rider GCB7 applies the pricing under the applicable BES tariffs to such accounts.

****206** ComEd notes that, contrary to the City's assertion, Section 16-125A of the Act does not mandate a rate reduction. Rather, ComEd argues that Section 16-125A provides that the utility's tariffs have to provide for 'governmental customers to work cooperatively in the purchase of electric energy *to aggregate their monthly kilowatt-hour energy usage and monthly kilowatt billing demand.* ' 220 ILCS 5/16-125A (emphasis added). Proposed Rider GCB7 provides for such aggregation.

ComEd states that it is a distribution company, and its distribution rates must reflect ComEd's costs. The City suggests that 'a method needs to be found that will allow the Alliance members to consolidate the accounts to achieve rate reductions on the delivery services side of their bills.' However, ComEd counters that distribution facilities to serve various governmental units - from Midway Airport to the Daley Center, - are physically distinct, and cannot be combined in any logical, meaningful way for purposes of deriving ComEd's costs to serve these customers.

Staff

Staff does not object to ComEd's proposed Rider GCB7 - Governmental Consolidated Billing 2007, which replaces existing Rider GCB - Governmental Consolidated Billing. (ICC Staff Exhibit 7.0, pp. 7-8)

City-CCSAO

***346** City-CCSAO argues that ComEd's proposal to replace Rider GCB with Rider GCB7 violates section 16-125A of the Public Utilities Act, which requires ComEd to offer tariffs permitting the Local Government Electric Power Alliance (the 'Alliance') 'to aggregate their monthly kilowatt-hour energy usage and monthly kilowatt billing demand.' 220 ILCS 5/16-125A(a). Mr. Walter testified that by placing on Rider GCB accounts that have offsetting load profiles, the Alliance has been able to save up to $10 million per year in demand charges. City-CCSAO asserts that Rider GCB7 would continue to permit load consolidation by Alliance members but would eliminate the cost savings currently available under Rider GCB.

City-CCSAO notes that ComEd does not deny that the purpose of section 16-125A, which was enacted as part of Illinois' 1997 deregulation legislation, is to allow Alliance members to realize cost savings. City-CCSAO also points out that Mr. Crumrine was unable to identify any economic benefit to Alliance members of allowing them merely to 'consolidate' their billing, as Rider GCB7 would. Without the rate reduction currently provided by Rider GCB, City-CCSAO continues, there is no benefit to load aggregation, and no reason to enact a law requiring such consolidation.

Commission Analysis and Conclusion

ComEd proposes to replace its current Rider GCB with Rider GCB-7, Governmental Consolidated Billing 2007. ComEd says that its proposed Rider GCB-7 allows certain governmental customers to consolidate their billings by selecting a single day each month as the due date for payment of bills. ComEd added that Rider GCB-7 does not contain provisions establishing separate demand charges for these customers, based on maximum and coincident demand of the governmental accounts. ComEd states that rather, the proposed rider applies the charges under the BES tariffs applicable to these accounts. The City/CCSAO wants ComEd to retain current Rider GCB and for the Commission to prevent ComEd from implementing Rider GCB-7. To evaluate ComEd's proposed Rider GCB-7, the Commission must first evaluate the applicable provisions of Article XVI of the PUA.

****207** Section 16-125A, in relevant part, states:

'(a) The tariffs of each electric utility serving at least 1,000,000 customers shall permit governmental customers acting through an intergovernmental agreement that was in effect 30 days prior to the date specified in subsection (b) and which provides for these governmental customers to work cooperatively in the purchase of electric energy to aggregate their monthly kilowatt-hour energy usage and monthly kilowatt billing demand.

(b) In implementing the provisions of this Section, the rates and charges applicable under the combined billing tariff of the service utility in effect on May 1, 1997 shall apply to all load of eligible government customers selected by the governmental customers including, but not limited to, load served under contract.'

(220 ILCS 5/16-125A (a) & (b)).

The only other applicable provision of Article XVI to the particular group of governmental customers described in Section 16-125A sets forth ComEd's delivery services rate offerings. Section 16-104(a)(2) states:

'On or before October 1, 2000, the electric utility shall offer delivery services to the eligible governmental customers described in subsections (a) and (b) of Section 16-125A if the aggregate coincident average monthly maximum electrical demand of such customers during the 6 months with the customers' highest monthly maximum electrical demands during the 12 months ending June 30, 2000 equals or exceeds 9.5 megawatts.'

(220 ILCS 5/16-104(a)(2)).

The Commission's read of these sections produces an entirely different outcome that those proposed by ComEd and City-CCSAO. Section 16-125A allows for the Alliance to aggregate monthly kilowatt-hour energy usage and monthly kilowatt billing demand in accordance***347** with a tariff containing rates in effect on May 1, 1997. ComEd developed and implemented current Rider GCB in response to this section. Nothing in Article XVI expressly states, or even suggests, that the tariff containing such rates should expire at the end of the rate freeze. As such, the Commission directs ComEd to retain current Rider GCB and to reject Rider GCB-7. To the extent that Rider GCB contains references to other rates that are being eliminated, the Commission directs ComEd to replace those references with the specific rates or formulas contained in the eliminated rates.

The Commission recognizes the conflict created by incorporating a rate (or rates) in Rider GCB that will not be available after January 1, 2007. Rider GCB, as amended in this Order, will only be applicable to a legislatively created subset of customers, not to the customers previously able to avail themselves of the rate(s) being eliminated. The Commission also recognizes that keeping this rate in place will likely lead to a revenue shortfall for ComEd. We encourage the parties to provide such potential revenue shortfall information in a petition for rehearing. More importantly, the Commission finds itself in a position where it believes it is without authority to reconcile the conflict created by the requirements of Section 16-125 A and the impending elimination of Riders 6 and 6L. At this point we are only able to acknowledge the conflict and thus we feel bound to require ComEd to retain the current Rider GCB even though the rates referenced in such Rider will no longer be available to any other class of customers in the very near future. We encourage the parties to address this serious statutory conflict during rehearing. If the Commission ultimately finds that there is a revenue shortfall for the company, the record should also contain proposed methods to recover such revenue gap from the remaining customer classes.

****208** Our analysis does not end here. Section 16-104(a)(2) requires ComEd to also make a delivery services rate available to those customers eligible to take advantage of Section 16-125A. The Commissions finds that ComEd offers several delivery services rates that may be applicable to Section 16-125A eligible customers. The applicable delivery services rate would depend on the individual customer or group of customers.

It is the City-CCSAO's position that the purpose of Section 16-125A is to allow Alliance members to realize costs savings by consolidating loads. This case deals with delivery service and Section 16-125A contains no reference to any delivery service subsidy to be provided to eligible governmental customers. Rather, Section 16-125A states that ComEd's tariffs must allow ‘governmental customers to work cooperatively in the purchase of electric energy to aggregate their monthly kilowatt-hour energy usage and monthly kilowatt billing demand. ‘ Rider GCB7 indisputably provides for such aggregation.

If, as the City/CCSAO request, ComEd were required to provide eligible governmental customers with a subsidy on delivery service charges in the post-transition period, unrelated to the costs these customers impose on ComEd's system, the costs and charges would have to be made up in other areas. The rates subject to approval in this proceeding make no provision for this subsidy. The City/CCSAO asserts that if ComEd ‘is truly concerned‘ about the inequities of providing this subsidy, ‘it should bear the cost itself. ‘ City/CCSAO Reply Br. at 8. This suggestion is neither reasonable nor appropriate.

14. RIDER QSW

ComEd

ComEd proposes Rider QSW, which replaces ComEd's existing Rider 3.

ComEd indicates that references in this rider to Rider POG should be maintained, rather than being changed to Rider 4 should the Commission reject ComEd's proposed Rider POG. In the event that Rider POG is rejected for some reason, ComEd asked that the text of the proposed Rider POG be replaced with the text of existing Rider 4, as appropriate, and that references to Rider POG be made in Rider QSW, in ***348** order to maintain consistency.

Staff

Staff does not object to Rider QSW - Qualified Solid Waste Energy Facility Purchases, which replaces existing Rider 3. Rider QSW sets forth the conditions by which ComEd purchases electric power from retail customers who have been found by the Commission to be Qualified Solid Waste Energy Facilities under Section 8-403.1 of the Public Utilities Act. (ICC Staff Exhibit 7.0, pp. 12-13)

Commission Analysis and Conclusion

There is no outstanding issue relating to Rider QSW, Qualified Solid Waste Energy Facility Purchases, which replaces existing Rider 3. The Commission finds that ComEd's proposed Rider QSW is reasonable and it is hereby approved.

15. RIDER TS

ComEd

ComEd points out that Rider TS-CPP was filed and fully considered by the Commission in the Procurement

Case (*See* Order, Docket 05-0159), and is not relevant to the instant case.

Commission Analysis and Conclusion

****209** Rider TS-CPP is not at issue in this case. Rider TS-CPP was approved in Docket 05-0159, and the Commission makes no findings or conclusions relating to this tariff.

16. RIDER TAX

ComEd

ComEd notes that Rider TAX is not at issue in this proceeding, and was only the subject of a passing reference by the CTA.

Commission Analysis and Conclusion

There is no outstanding issue relating to Rider TAX, relating to Municipal and State Tax Additions. The Commission finds that ComEd's proposed Rider TAX is reasonable and it is hereby approved.

17. RIDER ML

ComEd

[103] ComEd proposes Rider ML, which contains the monthly rental charges for meter-related facilities and replaces ComEd's existing Rider 7. ComEd notes that during the hearings, an agreement was reached between ComEd, CUB and the City with respect to residential RTP meter price and RTP meter service life. (Tr. at 2385:18-2387:9). ComEd asks that the agreement be approved by the Commission.

ComEd disputes CUB-City's assertion that ComEd should include productivity gains if ComEd is incorporating inflation in the labor rates. ComEd explains that the incorporation of productivity gains is inappropriate because the time estimates for performing meter exchanges used in the determination are based on fully trained employees. ComEd further articulates that the expected 4% per year increase in hourly employee wage rates in the determination of meter exchange charges is not an ‘inflation‘ factor as CUB-City suggests. Rather, ComEd notes that it is based on the current Collective Bargaining Agreement between ComEd and its employees.

Staff

Staff does not object to Rider ML - Meter-Related Facilities Lease. Staff reviewed the accuracy of the monthly rental charges for various meter classes and found no reason to contest the rates proposed for Rider ML. (ICC Staff Exhibit 8.0, p. 18) In rebuttal testimony, Staff witness Schlaf was concerned that CUB's real time pricing proposal may result in the overstating of usage. Dr. Schlaf's concern was based on ComEd's response to Staff Data Request RDL 7.01, which was received shortly before the filing of Staff rebuttal testimony and ***349** therefore was not incorporated into Staff's rebuttal testimony. (ICC Staff Exhibit 20.0, p. 9) ComEd subsequently reduced the meter lease charge applicable to residential customers. (ComEd Ex. 46.0, p. 31) The new charge is $5.36 per customer per month. Staff does not object to the revised charge. (ICC Staff Exhibit 24.0, p. 2)

Commission Analysis and Conclusion

Rider ML contains the monthly rental charges for meter-related facilities and replaces ComEd's existing Rider 7. Issues related to real time pricing meters are addressed elsewhere in this order. The Commission notes that while CUB and the City raised certain issues in testimony, neither addressed Rider ML in their briefs.

To the extent CUB and/or the City maintain that meter rental charges should reflect increased productivity in performing meter changes, the Commission rejects this argument. ComEd has explained why this suggestion is improper and the Commission concurs with ComEd's stated rationale. The cost of capital issue is addressed elsewhere in this Order. Rider ML, as proposed by ComEd, is reasonable and it is therefore approved with the modifications agreed to by ComEd and CUB/City with respect to the rental for a residential interval data recording meter, the Single Phase Watt-hour Meters with Interval Demand Recording (IDR) Registers, Self-Contained Class 100 or 200, as determined in ComEd Ex. 46.3.

18. RIDER RESALE

ComEd

****210** 104, 105] ComEd proposes Rider Resale to replace Rider 12 - Conditions of Resale or Redistribution of Electricity by the Customer to Third Persons ('Rider 12'). ComEd explains that the purpose of Rider Resale is to clarify that a reseller must resell electricity at a rate that does not exceed the average cost per kilowatt-hour that the reseller incurs for the electricity it resells. ComEd describes the reason for the new Rider RESALE as being an update to the rate-limiting provision in Rider12, which currently references Rate 6 - General Service and Rate 6L - Large General Service, to reflect that fact that Rider 12 customers today have a broader range of supply options.

ComEd agrees to revise Rider Resale to satisfy concerns expressed by other parties that the Rider is outdated and that a landlord should be able to charge varying electric rates to tenants due to the fact that tenants load profiles may warrant different rates. ComEd takes no position on Staff's recommendation that landlords who resell electricity should be certified as Alternative Retail Electric Suppliers ('ARES').

Staff

Staff witness Schlaf expressed concerns with respect to ComEd's proposed Rider Resale. (ICC Staff Exhibit 20.0, p. 15) First, he stated that it was not apparent why a building owner could resell electricity without first obtaining an Alternative Retail Electric Supplier ('ARES') certificate from the Commission. (*Id.*) Staff also argued in its Initial Brief that the new language contained in Rider Resale might be interpreted to broaden eligibility beyond the statutory provision defining 'retail customer' to include an entity which is receiving electric service from a public utility and was engaged in the practice of resale and redistribution of such electricity within a building prior to January 2, 1957. (Staff IB, p. 120; *see also* 220 ILCS 5/16-102) Second, Dr. Schlaf noted that even if a building owner could resell electricity, the proposed modifications would permit certain building owners to charge their tenants anything that they wished for the electricity they purchase from ComEd, as long as the price for the resold electricity is stated in a lease or agreement. (*Id.*) He noted that these modifications would create the possibility that electric rates and charges could vary considerably among the tenants in the same building. (*Id.*)

Notwithstanding the above-stated concerns, Staff stated in its Initial Brief that since it does not advocate requiring building owners ***350** that resell electricity to tenants within the buildings that they own to become certified as Alternative Retail Electric Suppliers, Staff does not object to the modifications to Rider Resale as expressed in ComEd witness' surrebuttal testimony. (Staff IB, p. 121)

BOMA

BOMA takes the position that the alternative language for Rider Resale BOMA proposed in response to ComEd's direct testimony would address provisions of Rider Resale that would have inadvertently prevented landlords from both properly allocating and fully recovering the costs of reselling electricity to tenants. (BOMA Ex. 1.0, pg. 15, ll. 322-325; pp. 17-18, ll. 379-399). BOMA notes that its proposed alternative language also is acceptable to ComEd, CES and IIEC. (BOMA In. Br., pg. 18).

IIEC

****211** IIEC states its original concern was with ComEd's Rider Resale reference to the phrase in the proposed language 'other adders applicable to the electric power and energy provided to such retail customer.' The nature of these adders was not specified in the tariff. The lack of specificity had the potential to either (1) create unnecessary confusion about what can be recovered by the customer providing the electricity, or (2) not allow customers providing electricity to recover legitimate costs associated with resale or redistribution of the power to the end-use customers. IIEC proposed that Rider Resale be modified to clarify that all legitimate costs associated with the resale or redistribution of electricity are allowed to be collected by customers.

IIEC says CES and BOMA witnesses raised similar concerns that the language proposed in the Resale Restriction section of ComEd's proposed Rider Resale could inadvertently be interpreted in a way that would not permit a customer redistributing electricity to fully recover their costs.

IIEC notes that after reviewing BOMA, CES and IIEC testimony, ComEd agrees the concerns are legitimate. ComEd adopts modifications suggested by BOMA witnesses Mr. Childress and Mr. Brookover which it believes adequately addresses all of the concerns raised and agrees to accept the proposed language if approved by the Commission. IIEC agrees the language adopted by ComEd in rebuttal adequately addresses the issues it raised as a concern.

CES

CES recognizes that ComEd agreed to revise the proposed Rider Resale in accordance with language offered by CES (and the Building Owners and Managers Association).

CES notes that as originally proposed by ComEd, Rider Resale would have caused serious problems. Some of the problems result from this rider's lack of clarity. Other problems result from the perpetuation of direct utility control of pricing by building operators to tenants; that pricing most appropriately can be handled in a competitive market through leases and rental provisions, with tariff-based pricing then serving as a fallback in the absence of a freely negotiated rental contract. (*See id.*)

Commission Analysis and Conclusion

Rider Resale was proposed to replace Rider 12 - Conditions of Resale or Redistribution of Electricity by the Customer to Third Persons. ComEd avers that the purpose of Rider Resale is to clarify that a reseller must resell electricity at a rate that does not exceed the average cost per kilowatt hour that the reseller incurs for the electricity it resells.

CES, BOMA and IIEC took issue with proposed Rider Resale, stating that it is outdated and a landlord should be able to charge varying electric rates to tenants due to the fact that tenants load profiles may warrant different rates. ComEd proposed revisions to Rider Resale that were intended to satisfy these concerns. It appears to the Commission that IIEC, BOMA and CES now agree with the revised Rider Resale as proposed by ComEd.

****212 *351** Staff expressed concern that Rider Resale might be interpreted in such a manner so that it is no longer applicable to a limited number of retail customers, namely an entity which is receiving electric service from a public utility and is engaged in the practice of resale and redistribution of such electricity within a building prior to January 2, 1957. In Staff's view, if such eligibility has been expanded, then those customers should seek certification as an Alternative Retail Electric Suppliers as they no longer meet the definition of ‘retail customer.‘ Staff says it does not object to the modifications to Rider Resale as expressed in ComEd's surrebuttal testimony.

With regard to proposed Rider Resale, the Commission finds that this tariff as modified by ComEd is just and reasonable and is hereby approved. We leave for another day the question of whether customers commencing resale after January 2, 1957, must obtain ARES certification.

19. RATE RDS (CTA)

Based upon its review of the record, the Commission finds that there are currently no contested issues relating to Rate RDS, Retail Delivery Service that is not addressed elsewhere in this order. Thus, the Commission finds that, except to the extent modifications are necessary to comply with other findings and conclusions in this Order, Rate RDS is reasonable and is hereby approved. (*See also* discussion of BES RR in Section III H.20, *infra.*)

20. RATE BES-RR

ComEd

[106] In its initial filing in this Docket, ComEd proposed to maintain a separate delivery class for its two railroad traction power customers, CTA and METRA, and to provide bundled electric service for that railroad class under proposed Rate BES-RR - Basic Electric Service - Railroad (‘Rate BES-RR‘).

ComEd's initial filing proposed a single point of supply standard for each railroad customer.*See* ComEd Ex. 10.1. In other words, any additions to either railroad system would be considered a non-standard facility subject to charges under Rider NS, unless such addition were to result in an increase in the entire load of the railroad customer's integrated electric traction power system that would require an increase in the railroad customer's standard installation. Alongi/McInerney Reb., ComEd Ex. 24.0, 39:983-89. According to ComEd, this proposal was a continuation of the practice initiated under an amendment to the CTA contract in 1998.*Id.*;*see also* Crumrine/Alongi Sup. Rep., ComEd Ex. 47.0, 24:500-17. Specifically, the 1998 amendment to the CTA contract, as a condition of CTA's desire to take service under Rate 6L - Large General Service (‘Rate 6L‘) and Rider GCB, incorporated Rider 6. Alongi/McInerney Sur., ComEd Ex. 41.0 Corr., 24:561-25:570. Thus, ComEd avers, the 1998 amendment adopted a single point of service standard for the entire CTA traction power system load consistent with standard service under Rate 6L.*Id.* Since 1998, ComEd states that it has applied and CTA has paid non-standard services and facilities charges for services based on the single electric service station standard consistent with Rate 6L and Rider 6.*Id.*

****213** In response to CTA's request that one initial service line to each individual CTA traction power substation be considered standard service by ComEd and not subject to the Company's proposed Rider NS, ComEd indicates that it is amenable to providing one service line to each individual CTA traction power substation as a standard service, subject to Commission approval and contingent on certain conditions described in more detail herein. Alongi/McInerney Sur., ComEd Ex. 41.0 Corr., 26:603-5. ComEd explains that it has not identified all the specific tariff revisions that would be necessary to implement this proposal, but made an initial attempt to do so, which can be found in CTA Cross Ex. 2.0 (Attachment 5). ComEd notes that this proposal would affect Rate RDS, Rate BES RR, and General Terms and Conditions.*Id.* According to ComEd, this proposal would preclude the need to retain a separate railroad delivery class for purposes of applying charges ***352** for delivery service, and also would preclude the need for a separate bundled service rate for railroad customers (*i.e.*, Rate BES RR).

ComEd comments that its agreement to provide one service line to each individual CTA traction power substation is subject to Commission approval, and contingent on certain conditions. ComEd states that each CTA traction power substation would be classified as a separate retail customer. ComEd proposes that each such substation be considered individually for determining the applicable delivery service class, determining standard distribution facilities, and applying delivery service charges. ComEd states that the following items provide specific aspects of ComEd's proposed treatment of each CTA traction power substation as a separate customer:

• The DFC would be applied to the MKD determined separately for each such CTA traction power substation;

• The standard service provided by ComEd would be those off-property facilities necessary to serve the incremental new traction power system load at the individual CTA traction power substation;

• The standard service provided by ComEd for each CTA traction power substation would be subject to a refundable advance deposit as provided in Rider DE - Distribution System Extensions;

• The single point of delivery standard for the CTA's total traction power system load provided for under the 1998 Amendment of the CTA's contract would cease to be effective;

• Each existing and new CTA traction power substation would be billed on a separate retail customer account and the CTA could elect to receive a summary bill of such accounts; and

• ComEd's offer and these same attendant conditions would apply to ComEd's other railroad traction power customer, Northern Illinois Regional Commuter Railroad Corporation (‘NIRCRC‘). This condition maintains consistency among similarly situated railroad customers.

Alongi/McInerney Reb., ComEd Ex. 41.0 Corr., 27:616-34. ComEd also outlined the types of service requests that would be considered non-standard under this proposal. These criteria are set forth in the surrebuttal panel testimony of ComEd witnesses Alongi and McInerney.*Id.* at 28:642-60.

****214** ComEd indicates that the conditions imposed are consistent with the rate design to recover the cost of providing such standard service to each individual railroad traction power substation. Further, ComEd avers that these conditions also are consistent with the rate design and standard service provided for other retail customers classified in the same customer class based upon the customer's demand established at the customer's individual premises.*Id.* According to ComEd, these criteria are consistent with the provision of such non-standard services and facilities provided under Rider NS to other retail customers, relevant provisions of the railroad contacts, as well as cost-causation and cost recovery-principles.*Id.* At 28:661-64.

ComEd comments that although Staff is correct that the Commission can terminate the railroad contracts, ComEd is not proposing to do so. Rather, ComEd's proposal described above would treat these customers in a fashion that is consistent with the costs that these customers impose on the distribution system. ComEd proposes, subject to the Commission's approval, to incorporate appropriate language in its General Terms and Conditions that would make it clear that the relevant provisions of these tariff contracts continue to apply in all such circumstances (*i.e.*, for situations in which such contract customers take delivery service under Rate RDS as well as for situations in which such contract customers receive full requirements electric supply from ComEd). ComEd proposes to include the appropriate revisions in its compliance filing at the conclusion of this Docket.

In response to CTA comments regarding the elimination of the over 10 MW customer class, ComEd argues that there simply is no justification in the record to allow CTA, or any non-residential customer with multiple non-contiguous locations in ComEd's service territory, ***353** to be billed at a distribution rate no higher than that for a customer with a load of 10 MW or more at a single contiguous location.*See,e.g.*, Crumrine/Alongi Sup. Rep., ComEd Ex. 47.0, 19:401-20:415. ComEd disputes CTA's claim that the CTA is served in the same way as other customers with loads of 10 MW or more. ComEd notes that the CTA and METRA together take service for traction power at 70 different non-contiguous locations in ComEd's service territory, and that the load at each traction power substation is typically between 1 and 5 MW, none of which exceeds 10 MW individually.*Id.* In contrast, other customers with loads of 10 MW or more are typically served at a single location.*Id.* Furthermore, each of those 70 railroad traction power substations is served through two ComEd 12,000 volt lines, whereas most other customers with loads of 10 MW or more that are not in the High Voltage Delivery Class are typically served through one or two 34,000 volt ComEd lines or one to five 12,000 volt ComEd lines.*Id.*

In response to CTA's questions regarding the increase in the Distribution Loss Factor (‘DLF‘) for the CTA, ComEd explained DLFs, how they are calculated, and the reasons for the increase in the Railroad Delivery Class DLF. DeCampli Reb., ComEd Ex. 14.0 Corr., 17:338-21:413.

****215** ComEd notes that provisions in the proposed General Terms and Conditions that the CTA interpreted as potentially requiring ‘unexplained changes in [CTA] infrastructure‘ are merely restatements of currently effective tariffs on file with the Commission contained in ILL. C.C. Schedule No. 9 - Information and Requirements for the Supply of Electric Service (‘ILL C.C. No. 9‘).

Staff

Staff does not object to ComEd's proposed Rate BES-RR - Basic Electric Service-Railroad, which replaces two existing special contracts for rail service providers. (ICC Staff Exhibit 7.0, pp. 11-12) ComEd will be acquiring energy from third party providers beginning in 2007. Thus, tying the energy cost of the service to the auction process and serving the customer under delivery services tariffs appears to be appropriate. (*Id.*)

Commission Analysis and Conclusion

See the Commission Analysis and Conclusion under Railroad Class.

21. GENERAL TERMS AND CONDITIONS

ComEd

ComEd proposes various modifications to its General Terms and Conditions. Alongi/ McINerney Dir., ComEd Ex. 10.0, 33:763- 34:797. ComEd initially proposed to remove the energy audit language that is currently contained in ComEd's existing Terms and Conditions because it is outdated and refers to a program that was once mandated by law but has long since been discontinued.*See* Alongi/McInerney Sur., ComEd Ex. 41.0 Corr., 20:451- 21:479. According to ComEd, this service has not been used by a single customer in at least 13 years.*Id.* ComEd subsequently agreed with Staff that it is reasonable to address the issue of energy audits in the upcoming energy efficiency rulemaking. It is ComEd's understanding that there are no contested issues with respect to ComEd's proposed General Terms and Conditions. Accordingly, ComEd recommends that the proposed modifications be approved.

Staff

Staff does not object to ComEd's proposed increases in several charges contained in the General Terms and Conditions, but does take issue with the elimination of an energy audit service. (ICC Staff Exhibit 18.0, p. 4)

ComEd offers an energy audit service to residential customers for $15. In response to Staff's opposition, ComEd proposed that customers use an ‘Energy Advisor do-it-yourself energy audit‘ offered via the internet. (ComEd Ex. 24.0, p. 28) ComEd modified its website so customers can be transferred, or linked, to the Energy Advisor website. (*See* ComEd Exhibit ***354** 24.5, showing the ComEd and Energy Audit web pages) Staff witness Hanson reviewed the Energy Audit website and found that it is not identical to the service included in the tariff. (ICC Staff Exhibit 18.0, p. 3) Moreover, Staff is concerned that lower income customers may not have access to the internet to take advantage of the replacement program ComEd has proposed. (*Id.*).

In surrebuttal testimony, ComEd proposed that this issue be addressed in the upcoming rulemaking regarding energy efficiency. (ComEd Exhibit 41.0, p. 21) Staff does not oppose that proposal. Staff withdraws its opposition to the elimination of the energy audit service and will address the issue in the upcoming energy efficiency rulemaking. (Tr. 1169-70) *Commission Analysis and Conclusion*

****216** The Commission has reviewed the record and it appears that, other than making conforming changes to implement other provisions of this Order, no contested issue remains relating to ComEd's proposed General Terms and Conditions. As a result, the General Terms and Conditions portion of ComEd's proposed tariffs with appropriate modifications to implement other provisions of this Order are hereby approved.

22. PROPOSED CHANGE IN DEFINITION OF MAXIMUM KILOWATTS DELIVEREDComEd

[107] ComEd proposes to change the way demand as measured by Maximum Kilowatts Delivered (‘MKD‘) for certain large customers is defined for billing purposes. ComEd recovers the costs of providing standard distribution facilities differently from different customer segments. For customers with loads over 400 kW that have meters that can record a customer's demand at regular intervals over the day, ComEd states that it currently charges such customers only for the maximum demand during the billing month that is recorded in the currently effective Demand Peak Period, defined to be from 9 am to 6 pm, Monday through Friday, excluding certain days recognized as holidays. Crumrine/Alongi Sup. Rep., ComEd Ex. 47.0, 4:82-5:98. According to ComEd, this group of customers is most greatly affected by ComEd's proposal to modify the definition of billing demand, which is called the Maximum Kilowatts Delivered or MKD. [FN32]

ComEd proposes that the MKD be determined on the highest 30-minute demand in the billing month, no matter what time of the day that occurs (*i.e.*, a 24-hour MKD).*See* Crumrine Dir., ComEd Ex. 9.0 Corr., 44:961-45:981; Crumrine/Alongi Sup., ComEd Ex. 46.0, 22:470-23:477; Crumrine/Alongi Sup. Rep., ComEd Ex. 47.0, 5:94-98. ComEd states that the MKD currently is measured for this group of customers as the highest 30-minute demand during the Demand Peak Period in a billing month.*See* ComEd's Rate RCDC, Sheet No. 117.

ComEd indicates that several observations are critical for understanding the context of its proposal. First, ComEd comments that while there is an implication from certain parties that rejection of ComEd's proposed 24-hour MKD is simply maintaining the *status quo*, this assertion is incorrect. ComEd maintained that its proposal provides a coherent basis for (a) the determination of the delivery classes applicable to customers; (b) the determination of the standard distribution facilities provided to customers; and (c) the determination of the charges applicable to customers for those standard distribution facilities.*See* Crumrine Sur., ComEd Ex. 40.0 Corr., 10:208-16. ComEd argues that rejecting its 24-hour MKD proposal would cause a disconnect between these various tariff conditions.

Second, ComEd notes that the Commission already has determined that customers should be grouped based on a 24-hour demand basis for the creation of supply groups in the Procurement Case. ComEd's proposed 24-hour MKD is a consistent approach to classifying customers, which minimizes customer confusion between delivery and supply categories and ***355** sends better price signals to customers.*See id.* at 10:218-11:223.

****217** Third, ComEd states that the vast majority of customers would not be affected by this proposal. ComEd notes that only those customers with interval demand recording ('IDR') metering, generally customers with over 400 kW of demand, would be affected by this proposal. According to ComEd, of these customers, only those that have large demands outside the Demand Peak Period would see any noticeable change in MKD relative to the current definition. Crumrine Reb., ComEd Ex. 23.0, 10:206-9.

Fourth, ComEd notes that the customers affected by this proposal are ComEd's largest load customers. ComEd avers that because of the size of the demand of these customers, ComEd generally must install facilities that are sized to meet that customer's maximum demand. This, ComEd argues, means that shifting load from peak to off-peak not only does not, but cannot, have an effect on the manner in which ComEd sizes its distribution facilities to serve these customers. The effect of these customers shifting load is that other non-residential customers that cannot shift load to off-peak pay for these costs.*See id.* 10:206-11:215, Crumrine Sur., ComEd Ex. 40.0 Corr., 11:224-33; Crumrine/Alongi Sup., ComEd Ex. 46.0, 21:444-22:459.

Finally, ComEd explained that the issue fundamentally boils down to one of fairness.*See* Crumrine/Alongi Sup. Rep., ComEd Ex. 47.0, 4:72-75. ComEd's current tariffs only bill customers for usage during the predefined Demand Peak Period.*See* Crumrine/Alongi Sup. Rep., ComEd Ex. 46.0, 26:555-27:557. According to ComEd, customer who largely uses the distribution system outside of the Demand Peak Period receives a free ride under the current MKD definition. While ComEd must size its distribution facilities to meet this customer's maximum demand, the customer only pays for those facilities to the extent that maximum demand occurs in the Demand Peak Period. It is ComEd's position that this violates one of the most fundamental principles of rate design (*i.e.*, customers should pay for the costs they cause the utility to incur) and is blatantly unfair to other customers who have to pay for this subsidy.*See* Crumrine Reb., ComEd Ex. 23.0, 11:218-31; Crumrine Sur., ComEd Ex. 40.0 Corr., 15:310-16; Crumrine/Alongi Sup. Rep., ComEd Ex. 47.0, 4:70-78.

ComEd argues that its proposed MKD definition reflects the manner in which ComEd's distribution facilities are sized, and in turn matches the cost-causation for these facilities better than using a Demand Peak Period to set MKD. ComEd discussed that the IIEC correctly noted that ‘the costs …ComEd incurs in providing delivery service are driven by the highest total demand on each piece of distribution equipment used to provide service.‘ IIEC Verified Comments at 2 (emphasis added). However, in contrast to the IIEC's suggestions, ComEd avers that it is not relevant what time of day customers affected by this proposal reach their maximum demand for the purposes of distribution planning and investment; it is the customer's maximum demand on ComEd's facilities that drives ComEd's investment. Crumrine Reb., ComEd Ex. 23.0,10:207-11:215; Crumrine Sur., ComEd Ex. 40.0 Corr., 15:319-27; Crumrine/Alongi Sup. Rep., ComEd Ex. 47.0, 10:200-03, 10:214-11:222.

****218** ComEd conducted a survey of all retail jurisdictions in the United States that have some form of restructuring in place as of January 1, 2006.*See* Crumrine/Alongi Sup., ComEd Ex. 46.0, 24:498-520; Crumrine/Alongi Sup. Rep., ComEd Ex. 47.0, 14:288-15:320; ComEd Ex. 47.1. According to ComEd, the majority of utilities in the survey utilized off-peak demand in setting prices either through the use of a 24-hour MKD (32%) or through some other method of valuing off-peak demand (32%). Therefore, ComEd posits that its proposed 24-hour MKD that recognizes that off-peak demand as a critical factor in setting distribution tariffs is largely in line with the rest of the country. ComEd's suggests that its current MKD definition that utilizes no demand ratchet and measures MKD in the Demand Peak Period, is out of step with the rest of the country.

****356** Staff*

Staff contests ComEd's proposal to change the time period for determining the maximum demands used to calculate the demand cost component of the bill for nonresidential ratepayers. ComEd proposes to use the maximum demand incurred by each individual ratepayer during a month, regardless of the time of day. (ComEd Ex. 9.0 Corrected, p. 45) Staff proposes that demand charge not be changed, and that demand charges for nonresidential ratepayers continue to be based on ComEd's peak period demands. In support of its position, Staff states that peak demand is best selected based on the usage of groups of ratepayers, not individual ratepayers. Moreover, the current method encourages ratepayers to shift their demands from the peak to off-peak periods of the distribution system.

Staff argues that ComEd is sending the wrong price signals to ratepayers. Staff points out that the distribution system (exclusive of customer-related costs), for the most part, is designed to serve groups of customers. What drives these costs, therefore, are not the demands of individual customers, but rather groups of customers. As an example, Staff explains that distribution lines at any moment may carry the demands of numerous customers, and that the collective demands of those customers may be expected to peak during times of peak demand. Staff states that a ratepayer whose peak demand is at 3am should not cause a strain upon ComEd's distribution system capacity because the demands of other ratepayers, at that time, would be low. (ICC Staff Exhibit 6.0 Corrected, p. 50)

Staff proffers its position as being the more reasonable. Staff states that basing the demand component of a bill on ComEd's peak period demands is the more reasonable position. According to Staff, the peak period reflects that part of the day when demands on ComEd's distribution system are greatest. This also signals to ratepayers that their demands during peak periods are important factors in determining overall costs on the distribution system. At the same time, it will signal to ratepayers that off-peak demands are less costly from a system standpoint. Staff posits that these signals will encourage ratepayers to shift their demands from peak to off-peak periods and thereby promote efficient use of the distribution system. (ICC Staff Exhibit 6.0 Corrected, pp. 50-51)

****219** Staff's position also relies upon the principle of rate continuity. According to Staff, current tariffs, for both delivery and bundled services, base demand charge calculations solely on demands during the peak period. Staff argues that some ratepayers have established a pattern of behavior, or installed equipment, to take advantage of the current definitions. ComEd's proposal, Staff avers, would require ratepayers to change their demands to a new set of definitions, and Staff asserts that that change could prove costly for those ratepayers. (ICC Staff Exhibit 6.0 Corrected, p. 51)

CTA and Metra

The CTA and Metra oppose ComEd's proposal to change the definition of demand to a Maximum kW Demand (MKD) such that ComEd measures demand over a 24-hour period rather than the current 9-hour peak. CTA and Metra agree with ComEd that if the MKD were only to be applied to the Railroad Class, the change would not be significant. However, CTA and Metra argue that the price each is charged should be no higher than the price charged to customers in the 10 MW and above class. CTA and Metra contend that if they are billed as part of the 10MW and above class, how demand is determined would make a significant difference in the amount each would be required to pay.

CTA and Metra contend that the MKD method of determining demand is flawed. They argue that ComEd built its facilities to meet the peak demand for those facilities, which generally occur at the system peak. However, the Railroad Class does not peak during ComEd's system peak so that the distribution facilities are available for other customers to use during ComEd's system peak. More importantly, CTA and Metra argue, ComEd sought the MKD method to prevent customers from ‘gaming‘ the ***357** system; that is, moving the individual customer peak so that it does not coincide with ComEd's peak, thereby avoid paying demand charges. However, CTA and Metra explain that the Railroad Class does not peak at ComEd's system peak. Instead, the Railroad Class peaks in the winter, not the summer, and in the morning and not in the afternoon. Because the Railroad Class members cannot change the time of the rush hours in Chicago and the greater Chicago metropolitan area, CTA and Metra assert that the Railroad Class cannot ‘game‘ the system.

CTA and Metra also contend that ComEd has done no meaningful analysis to support its contention that only certain very large retail customers are able to shift load to off-peak hours. In fact, CTA and Metra argue that Metra witness Mitchell's unrebutted testimony is to the contrary. According to the testimony of Metra's Director of Energy Management, James Mitchell:

• Metra spends approximately $7 million per year on traction power for its electric train service district, and $4 million per year for its other electrical needs.

• The majority of electricity purchased for Metra's other needs is used at its standby yards where Metra's diesel engines and related passenger coaches are stored and serviced.

****220** • Since 1992, Metra has cut its electrical costs at its standby yards in half using a combination of demand management and conservation techniques.

• The abrupt change to a 24 hour MKD demand charge in all likelihood will cause Metra's electricity costs for its non-traction power purchases to double, from $4 million to $8 million.

According to CTA and Metra is but one of many larger retail customers whose electrical usage ComEd never studied and never considered. CTA and Metra contend that ComEd's proposed shift to a 24 hour MKD demand charge is an ill-conceived, environmentally damaging decision that will wreak serious damage on customers who have successfully shifted to off-peak usage. CTA and Metra contend that this ill-conceived initiative should be stopped in its tracks.

IIEC

IIEC recommends the current definition or method of determining MKD be retained. It says it is joined in this position by the Commission Staff, the Illinois Association of Wastewater Agencies ('IAWA'), and the Chicago Transit Authority ('CTA'). It points out no party supported ComEd's proposed change in the definition of, or the method of determining MKD, a fact it says ComEd has acknowledged.

IIEC argues that in the absence of compelling reasons to change the method, principles of rate continuity warrant retention of the current method. It points out this method has been in use in ComEd's tariffs for many years and was retained as part of the tariffs through ComEd's last two delivery service cases in ComEd Dockets Nos. 99-0117 and 01-0423.Thus, the current definition of MKD is a long-standing feature of ComEd's bundled service and unbundled delivery service rates according to IIEC. Therefore, IIEC says changing the current definition would not be consistent with the rate design principles of rate continuity and prevention of rate shock.

IIEC also argues that modification of the definition or method of determining MKD would introduce confusion or increased operating costs for customers who are familiar with the current demand measurement periods used to determine MKD. The existing demand measurement periods have provided price signals to encourage off-peak usage through the establishment of on-peak periods and charges for many years, through many rate cases, including all of ComEd's delivery service rate cases to date.

IIEC says retention of the current definition of or the method of determining MKD will ensure that those customers who have made investments to enable and facilitate their off-peak operation, to the benefit of the ComEd system in response to ComEd's long-standing rate design, will retain the financial benefit associated with those investments.

***358** IIEC also says retention of the current definition of MKD, contrary to ComEd's position, is more consistent with the well-established Commission policy of assigning costs to cost causers. IIEC says the time of day that customers establish their highest demands is a critical factor in the actual facilities cost incurred by the utility. These delivery service costs are driven by the highest total demand on each piece of distribution equipment used to provide the service. The cost of the portion of the distribution system comprised of facilities dedicated to individual customers are indeed driven by the highest demand of a single customer regardless of when that occurs. However, for facilities used to provide service to multiple customers, the cost of those facilities and thus, the resulting cost of service, is driven by the highest level of the combined demand (*i.e.*, total demand) of those customers served by such facilities according to IIEC. IIEC explained: '[T]his is not the same as the sum of the highest individual demands of all customers served by those facilities, …' a concept which ComEd wishes to incorporate into its rates for billing purposes by changing the definition of MKD. ComEd's proposal diverges from the principle of cost causation and results in higher costs to customers who lower distribution costs for ComEd as well as lowering costs of electricity delivery for all customers. While the current definition of, or method of determining MKD is not perfectly matched to cost causation according to IIEC, it is superior to ComEd's proposal. Therefore, it should be retained.

****221** Finally, IIEC argues the current definition of, and method for determining MKD, recognizes the beneficial impact of off-peak operation by those customers who operate primarily off-peak while using network distribution facilities. Load diversity can affect the sizing costs of network facilities for transmission and distribution. Customers agreeing to operate primarily in the off-peak periods by choice or necessity benefit the network by not contributing load to the system during general times of network stress. In addition, IIEC says these customers can favorably impact the commodity portion of the bills for customers who continue to buy power obtained through ComEd's power procurement process. IIEC reasons this is because the cost of power in off-peak periods tends to be lower than during on-peak periods and thus shifts in load from on-peak to off-peak periods served to lower the auction based supply costs resulting from ComEd's power procurement method, all other factors being held equal. IIEC says retention of the current definition of MKD would maintain these benefits.

IIEC notes ComEd proposed, in its surrebuttal testimony, to limit the increase in the facilities distribution charge for 10 MW and over customers to $3.86 per kW, assuming its position on the definition of, or method for determining MKD was accepted. ComEd says there is a relationship between its proposal to limit the facilities distribution charge and its proposal to change the definition of, or method for determining, MKD. ComEd claims this linkage is based on a hypothetical gaming opportunity that would somehow be created in the absence of the link. IIEC says there is no gaming opportunity created if the facilities charge is lowered and the current MKD definition is retained. There is no relationship between the facilities distribution charge and MKD that increases the possibility of the hypothetical gaming. IIEC argues the hypothetical ‘gaming‘ situation ComEd alleges would exist if the lower facilities charge and MKD are not linked, would exist regardless of whether or not ComEd's definition of MKD is adopted. IIEC says that using ComEd's flawed logic, the alleged gaming opportunity is actually easier under ComEd's proposed 24 hour MKD definition, as the artificial expansion of load would be cheaper if it occurs during the off-peak period. Thus, there is no reason to link the two proposals. Furthermore, IIEC says ComEd did not explain why this alleged gaming opportunity is suddenly a concern now, when the separate 10 MW and over class and current MKD definition have coexisted since delivery service rates first began in 1999.

For all the reasons it identified, IIEC recommends ComEd's current definition of MKD be retained and ComEd's proposal to change the definition should be rejected.

***359** *Commission Analysis and Conclusion*

For customers with demands in excess of 400 kilowatts, MKD currently is measured as the highest 30-minute demand during the Demand Peak Period in a billing month. ComEd is proposing that the MKD be determined on the highest 30-minute demand in the billing month, no matter what time of the day that occurs. That is, ComEd proposes to implement a 24-hour MKD.

****222** The Company claims that its proposed MKD definition reflects the manner in which its distribution facilities are sized. It also matches the cost-causation for these facilities better than using a Demand Peak Period to set MKD. According to ComEd, certain parties have alleged that ComEd's proposed MKD definition ignores the benefits of diversity of demand on the system. ComEd maintains that such claims are based on a faulty understanding of the types of customers the 24-hour MKD proposal would affect. It also is a complete misunderstanding of how ComEd plans and invests in its distribution system.

Staffs, Metra, the CTA and IIEC all oppose ComEd's proposed revision to the MKD definition. Each of these parties argue, essentially, that the proposed change will have significant adverse rate impacts for certain customers and that it would improperly take away the incentive for large customers to shift their demand from on-peak periods to off-peak periods.

The Commission has reviewed the record and it appears that ComEd is correct that with regard to electric distribution facilities the diversity of peak is not as significant as it is for electric generating facilities. In other words, the cost of providing distribution facilities does not depend on whether any particular customer has its peak during the period of system peak or during off peak periods. There are however, exceptions to this general proposition.

The Commission favors cost based rates and, thus, the next question to address is whether there are public policy considerations that warrant deviating from cost based ratemaking in this instance. Having reviewed the record and the parties' arguments, the Commission concludes some very important public policy implications come into play here. Staff and several consumer intervenors suggest there are benefits associated with encouraging customers to use electricity in the off-peak rather than on-peak periods. The Commission concurs.

ComEd emphasizes that it is now a delivery services company and suggests that generation or supply issues are no longer a concern for ComEd. However, the Commission believes ComEd oversimplifies the matter. In fact, it was ComEd that filed a petition in Docket 05-0159 that established the auction process under which electric generation or supply will be acquired for bundled electric customers. ComEd will acquire supply through the auction process approved in Docket 05-0159 and is not quite as removed from supply issues as it seems to suggest.

Similarly, the Commission cannot simply ignore the impact of its decision on the cost of electric generation or electric supply. Additionally, the Commission believes that there are environmental benefits associated with shifting electric demand from periods of peak to off-peak. Here the Commission believes that it is in the public interest to reject ComEd's proposed revision to the definition of MKD. The current definition provides an incentive for customers to utilize electricity during off-peak rather than on-peak periods. ComEd's arguments against the existing definition include a suggestion that some customers may game the system and that the current definition results in improper subsidies.

****223** With regard to ComEd's gaming concern, the Commission observes that at least two major customers, Metra and the CTA, have demonstrated that they are incapable of gaming the system as ComEd suggests. Even if ComEd were correct that some gaming of the system is inevitable, the Commission believes the benefits of the current definition likely exceed the costs associated with possible gaming.

With regard to subsidies, the Commission disagrees that the existing definition would result in improper subsidies. The Commission makes this finding based upon its conclusion that the benefits of encouraging off-peak usage ***360** exceed the adverse impact associated with the somewhat higher delivery rates charged to customers that use energy during on-peak periods. In conclusion, ComEd's proposed revision to the definition of MKD is rejected.

23. SINGLE MONTHLY PEAK VS. AVERAGE OF 3 PEAKS FOR MUNICIPAL PUMPING

See discussion of Proposed Change in Definition of Maximum kW Delivered in Section VIII.22 of this Order, *supra*.

24. MUNICIPAL PUMPING CLASS IN DEMAND-BASED CATEGORIES

ComEd

[108] ComEd proposes that water and sewage pumping customers be treated in the same manner as other customers with similar demands. Crumrine Reb., ComEd Ex. 23.0, 35:753-58. Thus, ComEd proposes that these customers take service under the appropriate delivery service class for each such customer's demand level. Crumrine Dir., ComEd Ex. 9.0 Corr., 40:872-42:897.

ComEd disputes IAWA's suggestion that the aggregation of load as it proposes recognizes the ‘benefits to the distribution system associated with this distribution of demand.‘ Menninga Dir., IAWA Ex. 1.0, at 6:102-4. ComEd noted that, rather, a pumping customer, just as any other customer, causes costs on the delivery system based on the individual maximum demand at each geographically separate pumping station.*See* Crumrine Dir., ComEd Ex. 9.0 Corr., 41:880-42:889; Crumrine Reb., ComEd Ex. 23.0, 36:767-74.

Commission Analysis and Conclusion

To the extent IAWA continues to request that the Commission allow water and sewer pumping customers to aggregate demands at various locations, that request is denied. The Commission finds that this proposal is inconsistent with cost based rates and that, in this instance, there is insufficient reason to deviate from cost based rates.

25. CREDIT FOR CTA'S OWN TRANSFORMATION AND DISTRIBUTION

ComEd

109, 110] ComEd stresses that it has charged the CTA only for the cost of facilities that are reasonably assignable to the CTA. ComEd notes that its ECOSS determines ComEd's cost to serve customers based on ComEd's costs.*Seegenerally* Heintz Dir., ComEd Ex. 11.0. Additionally, ComEd refers to an analysis prepared in 1997 which, according to ComEd, demonstrates that ComEd considered only the CTA's proportional use of each individual primary feeder and each ComEd transformer substation in developing the underlying basis for the nonstandard service charge under Rate 6L and Rider 6. ComEd argues that this is consistent with the cited provision of Rider 6 to charge only the cost of facilities that are reasonably assignable to the customer.*See* Crumrine/Alongi Sup. Rep., ComEd Ex. 47.0, 22:468-72; ComEd Ex. 47.5. ComEd articulates that CTA's equipment has no bearing on ComEd's costs.

****224** *CTA*

CTA asserts that it provides benefits to the ComEd system through facilities owned, built, paid for and operated by the CTA. CTA claims its traction power substations allow ComEd power and energy to flow freely in and out of CTA substations, adding reliability to the ComEd distribution system. In CTA's view, the distribution rate structure should provide credits to CTA for its power transformation, conversion and distribution facilities since these CTA operated and maintained facilities convert, transform and bring the power to its actual point of use.

CTA says it has made an enormous investment in power control, transformation, conversion and distribution facilities. CTA operates 59 power substations that receive the power from ComEd at 12,500 volts alternating current and ***361** convert it to 600 volts direct current. The CTA claims this power is distributed via CTA-owned power cables to the connection points on CTA third rails. The power travels up to two miles of third rail to the point of actual use for train power. The CTA indicates that this operation is overseen by CTA's control center which operates the distribution equipment via CTA-owned SCADA systems. Historically, many of the CTA substation facilities were once owned and operated by ComEd but CTA now assumes the full cost of construction, operation and maintenance of this power conversion and distribution infrastructure. According to the CTA, the distribution rate structure should provide credits to CTA for its power transformation, conversion and distribution facilities since these CTA operated and maintained facilities convert, transform and bring the power to its actual point of use. In addition, CTA claims it should not be required to subsidize other customers who do not provide similar power facilities of their own.

According to CTA, it is ComEd's position that CTA would not be eligible for any credit for any facilities it pays for that are dedicated to CTA use because the CTA is not eligible for any credit under Rider ZSS-7. The CTA maintains that because the CTA-owned substations allow power to flow over and back out onto the ComEd network, these facilities provide a benefit to all ComEd customers. As a result, CTA argues that because there is no specific credit back to the CTA for these facilities purchased with these payments, CTA is subsidizing all other customers on ComEd's distribution system.

Commission Analysis and Conclusion

CTA asserts that it provides benefits to the ComEd system through facilities owned, built, paid for and operated by the CTA. CTA claims its traction power substations allow ComEd power and energy to flow freely in and out of CTA substations, adding reliability to the ComEd distribution system. In CTA's view, the distribution rate structure should provide credits to CTA for its power transformation, conversion and distribution facilities since these CTA operated and maintained facilities convert, transform and bring the power to its actual point of use. ComEd argues that CTA's equipment has no bearing on ComEd's costs.

****225** The Commission has reviewed the record and rejects CTA's proposal that would require ComEd to provide credits to the CTA for customer owned transformation, conversion and distribution facilities. The Commission concludes that there has not been a sufficient showing that the CTA's facilities provide a meaningful benefit to ComEd or other customers. While it is true that physics dictate the flow of electrons on the ComEd/CTA distribution system, the CTA has not proven that its equipment, either by design or by chance, improves the reliability of ComEd's system or allows ComEd to avoid incurring costs. The fact that electricity flows onto and off of CTA's system according to the laws of physics does not necessarily mean that significant benefits accrue to ComEd or its other customers.

Even if one were to assume that CTA-owned equipment provided meaningful benefits to ComEd or other customers, the record is devoid of any way to quantify the benefits and no mechanism has been proposed to provide appropriate credits to CTA. The Commission emphasizes that, in any event, the record does not support CTA's underlying assumption that significant benefits are created. Finally, it appears the credits proposed by CTA are not part of its existing contract with ComEd. Thus, CTA's proposal is rejected.

26. SUPPLY ADMINISTRATION CHARGE

ComEd

111, 112] ComEd proposes that the costs of administering the supply function for bundled electric service customers, including associated administration and general (‘A&G‘) costs, should be recovered from the bundled electric service customers that cause these costs.*Seegenerally* Crumrine Dir., ComEd Ex. 9.0 Corr., 46:1007-48:1031. Accordingly, ComEd proposes that each proposed BES tariff contains***362** a corresponding Supply Administration Charge (‘SAC ‘).*Id.*;*see also* ComEd Ex. 10.1 and ComEd Ex. 10.7.

ComEd argues that its proposal fairly apportions the costs incurred by ComEd to provide bundled electric service to customers.*See* Crumrine Dir., ComEd Ex. 9.0 Corr., 46:1007-48:1031; Crumrine Reb., ComEd Ex. 23.0, 48:1020-49:1041. Specifically, ComEd proposes that these costs, which are fixed in nature, be recovered through a fixed SAC per month for each BES tariff.*Id.* ComEd proposes to allocate these costs utilizing a two step process: 1) first, the costs are allocated between each of the BES tariffs based on the total kWhs that ComEd provided to each of the Customer Supply Groups, and 2) the costs are allocated to each group utilizing the expected number of customers to arrive at a fixed per customer charge for each BES tariff. Crumrine Dir., ComEd Ex. 9.0 Corr., 46:1007-48:1031; Crumrine Reb., ComEd Ex. 23.0, 48:1020-49:1041.

ComEd argues that Staff's assertion that the SACs should be ‘recovered on a usage basis,‘ as opposed to the per customer basis proposed by ComEd, is unreasonable for three reasons. First, ComEd states that Staff's underlying assumption that the ‘level of [these] costs bears a closer relationship to usage than to the number of customers‘ is flawed. Crumrine Reb., ComEd Ex. 23.0, 48:1028-49:1041. ComEd commented that the costs reflected in the SAC are relatively fixed and do not vary with the volume sold or the number of customers served.*See,e.g.*, Crumrine Reb., ComEd Ex. 23.0, 49:1044-46.

****226** Second, while these costs are fixed in nature, ComEd proposes that they be allocated to the various customer groups based on usage because such costs are, in a limited sense, incurred to provide supply.*Id.* However, consistent with traditional ratemaking principles, ComEd proposes a fixed charge for the recovery of fixed costs.*Id.*

Third, ComEd indicates that Staff's proposal is not practical. ComEd points out that, with proposed SACs of as little as a penny per month for residential customers, it makes no sense to convert this charge into a per kWh charge.*Id.* at 49:1042-55.

ComEd opposes what it refers to as CES' arbitrary and unsubstantiated recommendation to ‘allocate no less than one-fourth of call center costs to supply.‘ ComEd commented that CES' proposed percentage is pulled out of thin air (Crumrine Sur., ComEd Ex. 40.0 Corr., 60:1358-61:1377), and is a transparent attempt to create ‘headroom‘ by artificially increasing the cost of BES rates.*Id.*

ComEd also argues, as referenced earlier in Sections II.C.2, II.C.3, and II.D.3 herein, that the General Plant and Intangible Plant costs, included in its proposed rate base, and the A&G expenses, included in its proposed operating expenses, should not be recovered through the SAC.

Staff

Staff proposes that the Supply Administration Charge (‘SAC‘) be recovered on a usage basis from bundled customers. The costs recovered through this charge pertain to the administration of the supply function for bundled service customers. (ComEd Ex. 6.0 Corrected, p. 47) Recovering the SAC through a usage charge is preferable to ComEd's proposal because the level of SAC costs bear a closer relationship to usage than to the number of customers (which is ComEd's proposal) and is more reasonable than ComEd's proposal. Given this positive correlation between costs and usage, SACs within individual auctions should be based on bundled usage levels, and not the number of customers. (ICC Staff Ex. 6.0 Corrected, pp. 48-49) Staff points out that ComEd witness Crumrine may believe that SAC costs do not vary with the number of customers, based on a quote from his rebuttal testimony.

Staff also claims that ComEd's proposal is internally inconsistent. Staff explains that ComEd allocates SAC costs between the BES auctions on a usage basis and within the auctions on a customer basis. Staff argues that this is illogical, and that Staff's proposal, to base SAC charges on usage throughout the allocation process, is clearly more reasonable. (ICC Staff Exhibit 17.0 Corrected, p. 36)

***363** *Commission Analysis and Conclusion*

ComEd argues that the costs that it will incur to administer the supply function for bundled electric service customers, including associated administration and general costs. It asserts such costs should be recovered from the bundled electric service customers that cause them. ComEd states that each proposed BES tariff contains a corresponding Supply Administration Charge (SAC).

****227** ComEd proposes that these costs, which are fixed in nature, be recovered through a fixed SAC per month for each BES tariff. ComEd proposes to allocate these costs utilizing a two-step process: 1) first, the costs are allocated between each of the BES tariffs based on the total kWhs that ComEd provided to each of the Customer Supply Groups, and 2) the costs are allocated to each group utilizing the expected number of customers to arrive at a fixed per-customer charge for each BES tariff.

Staff proposes that the SAC be recovered on a usage basis from bundled customers. Staff claims the costs recovered through this charge pertain to the administration of the supply function for bundled service customers. Staff believes that recovering the SAC through a usage charge is preferable to ComEd's proposal because the level of SAC costs bears a closer relationship to usage than to the number of customers and is more reasonable than ComEd's proposal.

The Commission observes that this issue involves the allocation of costs that cannot be directly assigned. As such, no allocation factor will be perfect. In the Commission's view, ComEd's proposed allocation factor is superior to Staff's. The Commission does not agree that supply administration costs are positively correlated with the amount of supply ComEd procures. Nor does the Commission believe that supply administration costs are positively correlated with number of customers. Nevertheless, the Commission finds that ComEd's allocation factor is superior. The Commission finds that the cost to be allocated is largely a fixed cost; therefore ComEd's allocation factor, which incorporates the number of customers, is superior to Staff's usage-based allocation factor.

The Commission finds CES' recommendation to allocate no less than one-fourth of call center costs to supply, to the extent CES still supports this recommendation, to be unsupported and unsubstantiated. Accordingly, that proposal is hereby rejected.

27. REAL TIME PRICING METERS AND ENERGY SMART PRICING PLAN

ComEd

ComEd expresses support for CUB's and the City's proposal, subject to two conditions. Crumrine Reb., ComEd Ex. 23.0, 46:996- 47:1014. First, ComEd indicates that the program must contain a cap in the tariffs for the number of residential customers for which ComEd would waive metering installation and removal costs equal to the total number of residential Rate BES-H customers assumed in whatever cost scenario or alternative analysis the Commission ultimately adopts.*Id.* Based on current calculations, ComEd is willing to waive the associated fees for no more than 70,000 customers at any point in time.*See* Crumrine Sur., ComEd Ex. 40.0 Corr., 52:1180-91. Second, ComEd predicates its support on the Commission's rejection of Staff witness Lazare's proposal to shift 20% of the costs reflected in the Customer Charges to the DFCs. Crumrine Reb., ComEd Ex. 23.0, 47:1008-14. ComEd argues that this condition is necessary because Staff's proposal has the potential of jeopardizing ComEd's cost recovery and the proposal would result in an increase in the costs to be recovered through the Customer Charge.

****228** ComEd rejects CUB's and the City's additional proposition that ComEd should equally share the risk of the program with customers. Thomas Reb., CUB/City Ex. 2.0, Corr., 7:151-52. ComEd indicates that this condition is not reasonable because the estimated number of participating residential customers, which is not exact, is the primary driver of the cost estimates. (Crumrine Reb., ComEd Ex. 23.0, 46:987-89; Crumrine Sur., ComEd Ex. 40.0 Corr., 53:1196-99)

***364** ComEd expresses no objection to making this proposal ‘competitively neutral‘’ (available for RTP programs offered by alternative suppliers) under two conditions. First, ComEd reiterates that the proposed cap must be approved because including RESs in the Proposal would place upward pressure on the number of participating customers.*Id.* at 54:1232-55:1246.Second, in implementing a competitively neutral program, ComEd recommends that any RES seeking to provide RTP to residential customers must:

(1) provide a sworn statement to ComEd that all such customers are, in fact, on an hourly energy pricing program, where the hourly prices directly reflect PJM Interconnection, L.L.C. (‘PJM‘) spot prices;

(2) provide advance notice to ComEd of when pricing in the customer's contract changes to something other than hourly energy pricing, so that the IDR metering can be exchanged as it would for a Rate BES-H customer;

(3) agree to submit to a periodic audit conducted by Staff (for which ComEd will reimburse the Commission for its travel and business expenses) of its applicable customer contracts; and

(4) assume financial responsibility for all charges and fees waived for such customer in the event it is determined that such customers are not or are no longer on a legitimate hourly energy pricing service from the RES.

Id. at 55:1247-56:1267.

Finally, ComEd agrees to work with stakeholders in an effort to educate customers about RTP. Crumrine Sur., ComEd Ex. 40.0 Corr., 56:1268-77. However, ComEd notes that such education efforts must fairly present *both* the potential advantages and disadvantages associated with RTP programs.

ComEd agrees with Staff that there may be cross-subsidy issues, but took the position that ‘this is a matter worthy of the suspension (at least, temporarily) of traditional ratemaking practices… .‘ Crumrine Reb., ComEd Ex. 23.0, 44:946-49; Crumrine Sur., ComEd Ex. 40.0 Corr., 56:1282-1285. However, ComEd indicates that, should the Commission share Staff's opinion that further research is needed before implementing the Proposal, ComEd's revenue requirement must be adjusted to recover the costs associated with the experiment.*Id.*

Staff

Staff witness Schlaf recommended that the Commission reject CUB's Real Time Pricing (‘RTP‘) proposal. (ICC Staff Exhibit 20.0, p. 6) Although a RTP program has potential benefits, Dr. Schlaf identified certain issues with CUB's proposal and recommended the Commission direct ComEd to undertake a two-year pilot program designed to obtain certain data necessary to address those issues.

****229** Dr. Schlaf explained that real-time pricing programs are a form of demand response ('DR').(*Id.*, p. 4) He stated that DR programs, which include energy efficiency programs and load reduction programs, encompass a wide range of policies that are designed to encourage customers to use energy more efficiently by, for example, shifting their consumption from periods when wholesale prices are relatively high to lower-priced periods. (*Id.*) Dr. Schlaf noted that implementation of DR programs could result in several societal benefits, potentially including a reduction in price volatility, improved reliability, and improvements in the environment. (*Id.*)

Further, Dr. Schlaf testified that the key to achieving such benefits lies in customers taking action to change their normal consumption patterns in response to market-prices. He stated that measuring customer consumption, however, requires the use of Interval Demand Register ('IDR') meters, which are typically more expensive than watt-hour meters. Dr. Schlaf testified that currently, incremental metering costs for switching from watt-hour meters to IDR meters are about $100 annually for ComEd residential customers. He concluded that since the $100 annual cost is a large fraction (approximately one-seventh) of an average residential customer's bill, few customers would voluntarily***365** pay for an IDR meter in order to take an RTP rate. (*Id.*, pp. 4-5)

After evaluating CUB's proposal, Dr. Schlaf stated that several benefits could flow from CUB's proposal. He noted, however, that quantification of these potential benefits, particularly the benefits to non-participants that might be achieved through lower wholesale prices and improvement in reliability, could be difficult. (*Id.*, pp. 5-6)

Dr. Schlaf testified that the price benefits available to non-participating customers could occur through reductions in bids offered by the bidders in the upcoming auctions. (ICC Staff Exhibit 22.0 (Corrected), p. 14) The magnitude of the potential reductions is dependent on the ability of residential RTP customers to affect wholesale prices through demand response. Staff questioned this ability given the size of the wholesale market in which ComEd obtains supply, the PJM Interconnection, a market that comprises about 135,000 MW of demand and a generating capacity of 160,000 MW. Dr. Schlaf calculated that causing a reduction of an amount as small as 1% in the overall demand of the PJM market would take the combined actions of around one million ComEd residential customers reducing their consumption at the appropriate time. (*Id.*, pp. 2021) In its Initial Brief, Staff noted that the CUB proposal envisions a customer participation rate of approximately one hundred thousand customers. (Staff IB, p. 130) Dr. Schlaf also discussed the costs associated with the CUB proposal, which include (1) metering costs; (2) promotional costs; (3) administrative costs; (4) costs associated with monitoring real-time prices; and (5) a 'loss of amenity' due to a reduction in lighting or cooling levels. (ICC Staff Exhibit 22.0 (Corrected), pp. 19-20) He noted that these costs, especially the metering, promotional, and administrative costs, can probably be estimated fairly accurately. (*Id.*, p. 20)

****230** Dr. Schlaf concluded, in view of the concerns expressed above, that the Commission should not adopt the CUB proposal at this time, and further stated that he would be reluctant to advocate a program in which all residential customers would pay for the costs of such program but only a small number of customers would benefit. (ICC Staff Exhibit 20.0, p. 6) Instead, Dr. Schlaf proposed that the Commission direct ComEd to undertake a two-year pilot program to determine whether evidence could be obtained that would show that the potential benefits of the CUB proposal would exceed the costs imposed on the customers that do not participate in the RTP program. (*Id.*, p. 7) Dr. Schlaf testified that an analysis of the type he proposed is needed in order to compare the costs and benefits of implementing the CUB proposal because very little data exists regarding the extent to which residential customers might respond to real-time prices. (ICC Staff Exhibit 22.0, (Corrected) p. 24)

Although Dr. Schlaf acknowledged the existing pilot program conducted by Community Energy Cooperative (‘CEC‘) in partnership with ComEd (with an enrollment of approximately 1,500 customers), that program does not address the key question of whether a large expansion of RTP, in the manner proposed by CUB, would be likely to produce net benefits for all customers. (ICC Staff Exhibit 22.0 (Corrected), pp. 19-22) Thus, he concluded that the results of the program, while perhaps indicative of the potential savings available to participating customers, cannot be relied upon to assure the Commission that all residential customers would benefit from the CUB proposal.

Dr. Schlaf stated that conducting a net benefits calculation would require a comparison of the sum of the identifiable costs that would be imposed on all customers with the sum of the potential benefits. In its Initial Brief, Staff noted that the Commission would be required to make such an assessment if Senate Bill 1705, which was passed on April 6, 2006, by both houses of the General Assembly without a single dissenting vote, is signed by the Governor. (S. 1705, 94th Illinois General Assembly, (2006))

Dr. Schlaf recommended that 2,000 customers participate in his proposed pilot program because it would provide reliable information about potential demand responsiveness of residential customers without unduly burdening non-participating customers. (ICC Staff Exhibit 22. 0 (Corrected), p. 25) Prior to beginning the ***366** program, Dr. Schlaf stated that the 2,000 participants would be provided with IDR meters so that their normal consumption patterns could be recorded; however, the participants would take service under the standard bundled rate during the first year. During the second year, he noted that the same group of customers would be placed on the RTP rate, and changes from the customers' typical consumption patterns would be identified. (*Id.*, p. 27)

Dr. Schlaf testified that the next step in determining the potential benefit of the RTP program would be to estimate the number of customers that would be willing to move to an RTP rate. He stated that incorporating the costs of equipping customers with IDR meters and comparing the costs with estimated level of net benefits would conclude the analysis. Staff witness Schlaf recommended that the analysis be conducted by a third-party, with assistance from ComEd, CUB, Staff, and other interested parties. (*Id.*, p. 596-601) Therefore, Staff recommends that the Commission accept Staff's RTP pilot program and reject CUB's proposal. (Staff IB, p. 133)

CUB-CITY

****231** CUB and the City propose a program to expand existing residential real time pricing (‘RTP‘) programs for up to 70,000 customers over three years. Currently there is an RTP pilot in ComEd's service territory with approximately 1,300 participants. CUB-City's proposal would expand the program incrementally from 15,000 customers in year one to 70,000 customers over three years. Additionally, CUB-City's proposal spreads the costs of the program over the entire residential customer base. CUB and the City profess that this program would reduce barriers to RTP participation and would provide valuable reliability benefits to the overall electrical system. CUB and the City maintain that, while questions regarding total net benefits cannot be specifically answered at this time, the available evidence supports moving forward.

CUB and the City point out that Real Time Pricing is an alternative rate structure that allows customers the opportunity to reduce their electricity expenditures by responding to prices as they occur. CUB-City Ex. 1.0 at 6, L. 103-09. CUB and the City state that customers receive price signals regarding peak prices from the utility a day in advance and can adjust their electricity usage accordingly. In addition to reducing electricity bills for RTP participants, CUB and the City argue that customer response to high prices benefits the entire system by reducing demand and decreasing the strain placed on the electricity grid during periods of high demand. Staff Ex. 20.0 at 6, L. 131-37.

CUB and the City assert that the price of electricity can vary significantly throughout the daytime hours, especially during periods of high demand, and, over the span of just a few hours prices may increase by as much as a hundred-fold. CUB-City Ex. 1.02 at ES-1. According to CUB and the City, consumers have historically been insulated from these price swings because they pay flat rates for electricity, which do not vary as the underlying price of electricity changes. CUB-City Ex. 1.0 at 6 L. 103-05. As a result, CUB and the City argue that consumers do not see the price of the electricity that they actually use. CUB and the City conclude that this lack of a transparent price signal causes customers to overconsume when electricity is scarce and prices are high, and under-consume when electricity is abundant, and prices are low. Such behavior, CUB and the City argue, strains the electricity grid and results in increased costs for consumers. Commissioner Cross Ex. 1.0 at 69-73.

CUB and the City note that, for customers to participate in RTP plans, ComEd must install meters with interval demand register ('IDR meters') that can record customer usage based upon when it occurs. CUB and the City acknowledge that the cost of these meters is significantly greater than the cost of ComEd's standard meters for residential customers and thus proposed that the Commission take action to spread the cost of RTP metering, across all residential customers to reduce financial barriers to participation. CUB-City Ex. 1.0 at 12-13, L. 236-49. If the costs are not spread across the class, stated CUB and the City, then the price of ***367** the meter will make participation prohibitive. CUB-City Ex. 1.0 at 8 L. 149-59.

****232** CUB and the City disagree with Staff's concerns regarding customer responsiveness to price. CUB and the City aver that the record demonstrates that customers do in fact respond to prices. CUB and the City point to the Center for Neighborhood Technology's Community Energy Cooperative ('CEC ') Energy Smart Pricing Plan ('ESPP'), which is a pilot residential RTP program sponsored by ComEd and the Illinois Department of Commerce and Economic Opportunity ('DCEO'). According to CUB and the City, the results of the ESPP demonstrate that: 1) Customers respond to price notifications; 2) Participants consume less electricity during high priced periods, indicating that they respond to price signals; and, 3) Customers are more aware of energy usage, as survey responses indicate.

To allay Staff's concerns regarding the benefits to all customers, CUB and the City point to the Department of Energy ('DOE') and International Energy Agency ('IEA') reports, Commissioners' Cross Exhibits 1 and 2, which describe the potential benefits of RTP and indicate that precise valuation of these benefits remains a challenging task. The IEA report is the first attempt to craft a consistent methodology for modeling system-wide net benefits. The DOE report was unable to estimate nationwide net benefits because of the inconsistent methodologies used by the past research in the U.S. However, CUB and the City maintain that, while exact quantification remains difficult, both of these studies indicate that benefits do exist. Based on this accumulated research, and the testimony supporting the potential benefits for Illinois consumers, CUB and the City argue there is enough evidence supporting their proposal to move forward with implementation. CUB-City Ex. 4.0 at 17, L. 362-71. CUB and the City's proposed program, they assert, will provide customers immediate benefits, both to individual users and system wide, and provide experience and data for a more complete and precise analysis of projected benefits in Illinois. ComEd Ex 46.0 at 19, L. 395-97.

While CUB and the City and ComEd agree on the cost and useful life of IDR meters, CUB and the City believe there are two other remaining issues: the appropriate cost of capital used to set ComEd's rates, and inclusion of inflation in meter exchange labor rates. According to CUB and the City, ComEd includes inflation to increase costs without also recognizing that cost reductions from efficiency gains likely will occur in the future. CUB and the City argue this is inappropriate because ComEd's cost will inevitably decline as the Company gains more experience with residential IDR metering and becomes more efficient. CUB and the City propose that these efficiencies be recognized by removing inflation from the cost of performing meter exchanges. CUB-City Ex. 2.0 at 14 L. 313-23.

If the Commission adopts CUB-City's proposals on these two issues, the monthly customer charges will be lower than ComEd proposed monthly customer charge. ComEd proposes a monthly customer charge of $0.09

for the administrator's low estimate of 30,000 participants, and a monthly customer charge of $0.16 for the administrator's high estimate of 70,000 participants. ComEd Ex. 46.1. As shown in CUB-City Exs. 4.03 and 4.04, CUB and the City claim that the appropriate customer charges should be $0.086 and $0.148, respectively, which provides ComEd the opportunity to recover its costs. CUB and the City maintain that dealing with this issue in the current rate case is the clearest method for implementing CUB and the City's proposal and ensuring cost recovery for the utility. CUB-City Ex. 4.0 at 17 L. 372-75. In fact, even though the exact rates have been a topic of disagreement, CUB and the City note that ComEd supports the CUB and the City's proposal. ComEd Ex. 23.0 at 42-43 L. 912-24.

****233** CUB and the City argue that Staff's proposal to conduct a load research program before expanding its recommended residential RTP program is unnecessary. Staff Exs. 20.0 at 7 L. 149-57; 22 at 26 L. 575-78. CUB and the City claim that customer behavior under the existing ESPP has been extensively researched, and the proposed budget for the expanded program includes an allocation for load research and program***368** evaluation. ComEd Ex. 23.2.

CUB and the City are concerned that Staff's proposed research plan is too small in scale and too short in duration to achieve the benefits that Staff desires. Without a significant real time pricing program in place, CUB and the City argue that it will be very difficult, if not impossible, to create a more precise analysis of net benefits in Illinois. The previous ESPP research shows that customers do respond to price signals, and a larger program should demonstrate the extent to which this response can be achieved on a larger scale for a longer time. CUB-City Ex. 4.0 at 13, L. 264-71.

As a result of CUB and the City's proposal, customers' annual electricity bills will increase by $1.80. However, CUB and the City aver that this rate increase would provide data and experience that is crucial to the future of Illinois consumers in restructured energy markets, and valuable rate options for residential end users, and would be a wise investment in the future reliability of the overall electricity system. CUB-City Ex. 4.0 at 17-18, L. 377-86.

CCSAO

CCSAO believes this important issue should be the subject of a separate proceeding by the Commission.

Commission Analysis and Conclusion

113-115] CUB and the City have proposed a program to expand existing residential real-time pricing (‘RTP‘) programs for up to 70,000 customers over three years. Currently there is an RTP pilot in ComEd's service territory with approximately 1,300 participants. CUB/City's proposal would expand the program incrementally from 15,000 customers in year one to 70,000 customers over three years. CUB/City's proposal spreads the costs of the program over the entire residential customer base. CUB and the City believe that this program would reduce barriers to RTP participation and would provide valuable reliability benefits to the overall electrical system.

CUB/City states that there are two outstanding issues between them and ComEd. The first is the appropriate cost of capital used to set ComEd's rates. This cost of capital affects the calculation of meter lease rates contained in Rider ML. In turn, these meter lease rates affect the program implementation costs necessary to implement CUB/City's proposal. The Commission's decision on this issue will affect the calculation of the meter lease charges in Rider ML.

CUB/City avers that the second issue of disagreement is ComEd's inclusion of inflation in meter exchange labor rates. They assert ComEd has included inflation to increase costs without also recognizing that cost reductions from efficiency gains likely will occur in the future. They believe this is inappropriate because ComEd's cost will inevitably decline as the Company gains more experience with residential IDR metering and becomes more efficient. CUB/City argues that these efficiencies should be recognized by removing inflation from the cost of performing meter exchanges.

****234** ComEd has agreed to the CUB/City proposal to: 1) include residential real-time pricing meters in the standard meter charge for residential customers; 2) work to expand the size of the Energy Smart Pricing Plan; and 3) provide RTP meters for every residential customer interested in RTP Programs. ComEd supports this Proposal subject to certain conditions.

According to ComEd, the Proposal seeks to allocate across all residential customers the cost of providing IDR meters to customers who request them. Under the Proposal, ComEd would add the program costs to ComEd's revenue requirement for residential customers and reflect such costs in the residential Customer Charge. ComEd states that all residential customers would pay the same Customer Charge, regardless of the tariff under which they take service. By allocating the costs in this manner, ComEd says all residential customers would bear the same percentage of the total costs associated with this program.

Staff argues that the Commission should not adopt the CUB proposal at this time, in part because it is reluctant to advocate a program in which only a small number of customers would ***369** benefit, but for which all residential customers would pay. Staff recommends that the Commission direct ComEd to undertake a two-year pilot program to determine whether evidence could be obtained that would show that the potential benefits of the CUB proposal would exceed the costs imposed on the customers that do not participate in the RTP program.

On June 30, 2006, Governor Rod Blagojevich signed into law Public Act 94-0777 (‘PA 94-0777‘), which modifies PUA Section 16-107 by setting forth detailed requirements for implementing RTP programs for utilities with 100,000 or more customers. Among other things, PA 94-0777 requires such electric utilities to file tariffs to allow residential customers to elect RTP. The Commission may approve these tariffs if it finds that the potential for demand reduction results in net benefits to all customers. CUB/City's proposal conflicts with the newly enacted legislation and therefore cannot be approved at this time. The Commission trusts that ComEd will file the appropriate tariffs in accordance with PA 94-0777 and that CUB/City will be active participants in the resulting proceeding.

28. DISTRIBUTION LOSS FACTORS

ComEd

See miscellaneous railroad issues, Section VIII.2(a) of this Order, *supra*.

Staff

Staff finds that the distribution loss factors in Rate RDS - Retail Delivery Service - were reasonable. (ICC Staff Exhibit 8.0, p. 19) Rate RDS provides the rates for ComEd to deliver power and energy to customers who have chosen to purchase all or a portion of their power and energy from suppliers other than ComEd. Staff witness Linkenback based his determination on his review of the technical data submitted by ComEd. Staff determined that the procedure used by ComEd to calculate the distribution loss factors was correct.

Commission Analysis and Conclusion

****235** There are no outstanding or contested issues relating to distribution loss factors, and those factors proposed by ComEd for purposes of this proceeding are hereby adopted.

29. REPLACEMENT OF RIDER 28 WITH RIDER LGC

ComEd

116-118] ComEd proposes replacing ComEd's existing Rider 28 with Rider LGC. As explained by ComEd, the purpose of Rider 28 and its proposed replacement, Rider LGC, is to recover the incremental costs incurred by ComEd in the event a local government unit requires ComEd to provide a service, or otherwise install, remove, replace, modify or maintain its facilities in a manner that is different from the manner in which ComEd would otherwise be required.*See,e.g.*, Alongi/McInerney Reb., ComEd Ex. 24.0, 15:385-91. Rider 28 currently recovers, and Rider LGC is proposed to recover, these additional costs directly from ComEd's retail customers located within the boundaries of such local government unit imposing the additional requirements. *See* ComEd Ex. 10.1, ComEd Ex. 10.2.

ComEd presented detailed evidence explaining that the differences between Rider 28 and proposed Rider LGC are not substantive.*See* Alongi/McInerney Reb., ComEd Ex. 24.0, 15:392-16:407; ComEd Ex 24.4. In rebuttal testimony, ComEd provided the changes between the riders in legislative style.*Id.* According to ComEd, this exhibit demonstrates that the changes are minor in nature and simply add clarity and organizational structure to the existing tariff language.*Id.* Additionally, ComEd also represented that it intends to administer Rider LGC ‘in the same manner‘ as Rider 28. Alongi/ McInerney Reb., ComEd Ex. 24.0, 17:438-43.

ComEd notes that the City's primary argument against Rider LGC, that it gives ComEd too much discretion, was rejected by the Commission in approving Rider 28. *See* ICC Dockets***370** 91-0146 and 91-0217, [cons.], (Order, Feb. 11, 1992). ComEd argues that the City has failed to identify any specific new language that grants this discretion.

ComEd contends that the City's assertion that Rider LGC may impair the City's rights under the existing franchise agreement with ComEd was equally meritless. ComEd discusses how the City misunderstood the language in the Rider, and how subsection (d) of proposed Rider LGC would not impair the City's right under its franchise agreement with ComEd (the franchise agreement requiring that ComEd remove at its expense any utility facility in the public way when the City has determined that such removal is necessary for certain purposes). First, ComEd notes that subsection (d) is a clarification of an existing practice.*See* Alongi/McInerney Reb., ComEd Ex. 24.0, 15:402-16:406. Second, ComEd points out that a 'like-for-like‘ replacement and relocation of ComEd's existing standard facilities for a road widening public improvement are not subject to the provisions of the rider. Rather, that is the reason for the ‘otherwise required‘ language in subsection (d).*See id.* at 16:415-422.

Staff

****236** Staff does not object to replacing Rider 28 with Rider LGC - Local Government Compliance Adjustment. Staff witness Hanson examined the differences between the two riders and expressed concern that some of the language contained in Rider LGC was not in Rider 28 and was unduly vague. (ICC Staff Exhibit 7.0, p. 7) In its rebuttal testimony, ComEd clarified certain aspects of how it will implement Rider 28 and how the language in the new tariff is unchanged from Rider 28. (ComEd Ex. 24.0, p. 16) Staff witness Hanson, in his rebuttal testimony, stated that ComEd's clarifications had addressed his concerns. (ICC Staff Ex. 18.0, p. 2)

City-CCSAO

City-CCSAO maintains that the broad language of Proposed Rider LGC renders unreliable ComEd's repeated assurances that Rider LGC is substantially the same as Rider 28. City-CCSAO cite in particular the claims of Messrs Alongi and McInerney that [t]he differences between existing Rider 28 and ComEd's proposed Rider LGC are not substantive and are not intended to change the purpose of the rider,‘ ComEd Ex. 24.0 at 15, L. 389-91, and that ‘ComEd's intention is to administer Rider LGC in the same manner as Rider 28 and ComEd does not intend to expand its discretion under Rider LGC as compared to Rider 28.‘*Id.* at 17, L. 440-42.

Relying on these assurances, Mr. Walter testified that the City expects that ComEd would not seek to recover through Rider LGC expenses incurred for projects undertaken other than pursuant to a City ordinance. Nevertheless, City-CCSAO assert that in their surrebuttal testimony, Messrs Alongi and McInerney identified in Rider LGC language that appears to expand materially the instances in which the rider would apply, including when a local government ‘requires as a condition of [ComEd's] use of its property‘ that ComEd furnish non-standard service. ComEd Ex. 41 at 10, L. 225-26. City-CCSAO state that under cross-examination, Mr. Alongi admitted that he did not know whether Rider 28 would apply in circumstances covered by the new language.*Id.*

at 1324.City-CCSAO add that the new ‘early replacement‘ provision included as subsection (d) of Rider LGC further belies ComEd's assurances that the differences between Rider LGC and Rider 28 are not substantive. In particular, City-CCSAO claim that ComEd has not clearly described the circumstances under which subsection (d) would apply. According to City-CCSAO, Messrs Alongi and McInerney's testimony that a replacement project is not covered by the provision if it is ‘otherwise required‘ - a phrase whose source has not been identified - only adds further confusion.

In addition, City-CCSAO contends that the Contract Clauses of the United States and Illinois Constitutions bar the Commission from approving Rider LGC.*See* U.S. Const., art. I, ' 10; Ill. Const. 1970, art. I, ' 16. Specifically, City-CCSAO claim that the Contract Clause is ***371** implicated by the ‘early replacement‘ provision of proposed Rider LGC because it would substantially impair the City's rights under section 9.4 of the City-ComEd electric utility franchise agreement, which requires ComEd to remove at its expense any utility facility in the public way when the City has determined that such removal is reasonably necessary for certain public purposes.*See* Ordinance and Agreement between the City of Chicago and Commonwealth Edison Co. (Jan. 1, 1992). Accordingly, City-CCSAO state that under subsection (d) of Rider LGC, ComEd could recover from City residents the costs of removing and replacing facilities at a different time than ComEd otherwise would remove them, even if the City had determined that removing the facilities was necessary for a public purpose subject to section 9.4 of the franchise agreement. Accordingly, City-CCSAO maintain that if approved, Rider LGC would violate the Contract Clause by substantially and retroactively impairing the City's rights under the City-ComEd franchise agreement without serving any significant and legitimate public purpose.

Commission Analysis and Conclusion

****237** ComEd proposes to replace existing Rider 28 with Rider LGC. ComEd claims there are no substantive changes between existing Rider 28 and ComEd's proposed Rider LGC. ComEd asserts that arguments very similar to those raised by the City were rejected when the Commission approved Rider 28.

According to ComEd, the purpose of Rider 28 and its proposed replacement, Rider LGC, is to recover the incremental costs incurred by ComEd in the event a local government unit requires ComEd to provide a service, or otherwise install, remove, replace, modify or maintain its facilities in a manner that is different from the manner in which ComEd would otherwise be required. ComEd says Rider 28 currently recovers, and Rider LGC is proposed to recover, these additional costs directly from ComEd's retail customers located within the boundaries of such local government unit imposing the additional requirements.

City/CCSAO state that ComEd identified in Rider LGC language that, in their view, expands materially the instances in which the rider would apply. Like Rider 28, Rider LGC would apply when a local government enacts an ordinance or ‘otherwise utilizes its constitutional or statutory powers to compel‘ ComEd to provide non-standard service. City/CCSAO asserts that unlike Rider 28, Rider LGC would also apply when a local government ‘requires as a condition of [ComEd's] use of its property‘ that ComEd furnish non-standard service.

According to the City/CCSAO, subsection (d) of Rider LGC would localize ComEd's costs when a local government required ComEd to remove and replace facilities at a different time than ComEd would ‘otherwise be required‘ to replace them. By contrast, section 9.4 of the City-ComEd franchise agreement requires ComEd to remove at its expense any utility facility in the public way when the City has determined that such removal is reasonably necessary for certain public purposes. The City/CCSAO assert that under subsection (d) of Rider LGC, ComEd could recover from City residents the costs of removing and replacing facilities at a different time than ComEd otherwise would remove them, even if the City had determined that removing the facilities was necessary for a public purpose subject to section 9.4 of the franchise agreement.

If approved, the City/CCSAO claim subsection (d) of Rider LGC would substantially and unreasonably alter the City's existing rights under the franchise agreement without serving any significant public purpose. City/ CCSAO contends that because the Commission cannot constitutionally approve a tariff that would impair existing contract rights, ComEd's proposal to replace Rider 28 with Rider LGC must be rejected.

The Commission has reviewed the parties' arguments as well as the evidentiary record on this issue. It appears that the basis for the City/CCSAO concern is the phrase ‘requires as a condition of the Company's use of its property‘ in the overview Section of proposed Rider LGC would result in the proposed Rider LGC operating in a manner that is different than ***372** existing Rider 28. The phrase at issue was not included in Rider 28 and ComEd has not adequately explained why the additional language is necessary.

****238** This is a non-issue for the Commission. ComEd witnesses Alongi/McInerney state in their rebuttal testimony that‘ ComEd's intention is to administer Rider LGC in the same manner as Rider 28 and ComEd does not intend to expand its discretion under Rider LGC as compared to Rider 28. Thus, whether this language is included is not relevant. As a result, ComEd is directed to exclude from Rider LGC the phrase at issue, identified above. ComEd is directed to administer Rider LGC ‘in the same manner‘ as Rider 28 was administered.

Thus, it appears that the City/CCSAO concern about the impact of subsection (d) has been eliminated. With the exception of the phrase that must be excluded consistent with this Order, the Commission finds Rider LGC to be reasonable and, with that phrase excluded, it is hereby approved.

30. RIDER ZSS7

ComEd

119, 120] ComEd proposes Rider ZSS7 to replace and additionally revise item (1) of the applicability conditions for Rider ZSS7 to require self generating customers to have direct access to the PJM markets. ComEd indicates that this proposal more closely follows the cost of service principles and sends appropriate price signals. Crumrine Dir. ComEd Ex. 9.0 Corr., 28:615-29-637; Alongi/McInerney, ComEd Ex. 10.0, Sched. 10.14, at 5.

ComEd explains that Rider ZSS7 applies only to those self-generating customers that operate under an Operating Agreement, the applicable Reliability Agreement and the Open Access Transmission Tariff of PJM to sell power and energy into the PJM market, and that Rider ZSS7 is designed to recover the cost of minimal distribution facilities on a direct assignment basis for each such customer. Crumrine Reb., ComEd Ex. 23.0, 76:1641-77:1670.

IIEC

IIEC recommends if ComEd's proposal to change the definition of MKD from an on-peak basis to a 24-hour basis is adopted by the Commission, that the eligibility provisions of Rider ZSS7, as proposed by ComEd, be modified to make all customers with generation eligible for service under that Rider.

IIEC says ComEd's proposed change in the definition of MKD can have a disproportionate impact on self-generation or cogeneration customers who require delivery service in any month to deliver power to replace the output of their generating unit. The impact is especially significant for customers who have either planned or unplanned generation outages that are most prevalent during the off-peak periods.

While IIEC strongly opposes ComEd's modification to the definition of MKD, it suggests that if the definition is changed as proposed by ComEd, IIEC's proposal to modify Rider ZSS7 would be to broaden the eligibility criteria to enable self-generation and cogeneration customers to have their cost of delivery service determined more directly (essentially on an individual basis) and billed through the zero standard service approach.

IIEC says that instead of making Rider ZSS7 available to all customers currently eligible for the Rider, ComEd's new rider will actually be applicable to 28% fewer customers (12 out of 33) than the original Rider ZSS. In an effort to remedy this situation, IIEC recommends the applicability provisions of current Rider ZSS be incorporated into ComEd's proposed Rider ZSS7, or otherwise modified to broaden, not narrow, eligibility should ComEd's proposed changes to MKD be adopted.

Commission Analysis and Conclusion

****239** ComEd proposes to revise item (1) of the applicability conditions for Rider ZSS7 to require self-generating customers to have direct access to the PJM markets. ComEd claims this proposal more closely follows the cost of service principles and sends appropriate price signals.

***373** If ComEd's proposal to change the definition of MKD from an on-peak basis to a 24-hour basis is adopted by the Commission, IIEC recommends that the eligibility provisions of Rider ZSS7, as proposed by ComEd, be modified to make all customers with generation eligible for service under that Rider.

The Commission, previously in this Order, rejected ComEd's proposal to modify the definition of MKD. As a result, it appears that the basis underlying IIEC's objection to proposed Rider ZSS7 no longer exists. Therefore, the Commission finds that ComEd's proposed Rider ZSS7 to be reasonable and it is hereby approved.

31. RATE BES-L

ComEd

ComEd proposed Rate BES-L (‘Basic Electric Service-Lighting‘) to amend two existing special service contracts (*i.e.*, contract with Chicago Park District and City of Chicago) covering service for street lighting. In 2007, ComEd will begin acquiring energy from third party providers. It is not appropriate for ComEd to offer special service contract pricing to selected customers, because the remaining customers would be subsidizing the prices the special service customers pay. Rate BES-L ties the costs of serving the Chicago Park District and City of Chicago to ComEd's delivery services and to its costs under the procurement process.

Commission Analysis and Conclusion

No party objected to ComEd's proposed Rate BES-L; thus, the Commission finds the proposed Rate to be appropriate and it is hereby approved.

32. TARIFF IMPLEMENTATION ISSUES

ComEd

[121] In light of the magnitude of changes being proposed by various parties in this proceeding, as well as the fact that the final Commission Order is scheduled to be entered several months in advance of the beginning date on which charges under the proposed tariffs would apply (*i.e.*, January 2, 2007), ComEd requests 30 days from the time the final order is entered in which to file its compliance tariffs. Alongi/ McInerney Sur., ComEd Ex. 41.0 Corr., 39:901- 40:925.

ComEd also proposes two additional housekeeping changes regarding its proposed rates.*See id.* ;Alongi/McInerney Dir., ComEd Ex. 10.0, 9:216-31. First, ComEd proposed that the Commission, in its order in this proceeding, direct ComEd to file a new Schedule of Rates with a new schedule number (*e.g.*, Schedule ILL. C.C. No.‘XX‘) within a reasonably short period of time after the mandatory transition period ends (*e.g.*, within eight months). ComEd indicates that this is necessary because ComEd's current set of rates will remain in ComEd's Schedule of Rates but will no longer be operational at the end of the mandatory transition period.*Id.*

Second, to facilitate a customer's ability to locate information in the new Schedule of Rates, ComEd requests that the Commission's order in this proceeding provide a variance to the tariff sheet numbering requirements contained in 83 Ill. Admin. Code 255.30(c), and instead allow ComEd to file its new post-2006 Schedule of Rates (*i.e.*, Schedule ILL. C.C. No. ‘XX‘) using the proposed tariff sheet numbering structure shown in ComEd Ex. 10.5.

Staff

****240** Staff's concern with ComEd's proposal is that given the voluminous tariff filings the Chief Clerk's Office receives, the Chief Clerk when accepting or rejecting tariff sheets relies on the consistency of the tariff sheet numbering rules contained in part 255. By allowing a variance it may create overall numbering problems that may be difficult to resolve in the future. Staff also noted that given the ICC's on-going development project for an electronic tariff filing system which is based on the tariff numbering rules set forth in Part 255 granting a variance to ComEd is a cause of great concern for Staff. ***374** Granting a variance like the one ComEd requests may jeopardize the development of an effective electronic tariff filing system. If other utilities are granted a variance like ComEd requests, significant programming and development changes would be required.

Commission Analysis and Conclusion

The Commission finds that ComEd should be directed to file its compliance tariffs within 30 days from the time the final order is entered in this case. ComEd is hereby directed to file a new Schedule of Rates with a new schedule number (*e.g.*, Schedule ILL. C.C. No. ‘XX‘) within eight months after the mandatory transition period ends. The Commission denies ComEd's request for a variance to the tariff sheet numbering requirements contained in 83 Ill. Admin. Code 255.30(c). The Commission agrees with Staff that allowing such a request may set a precedent for other utilities which would result in tariff sheet numbering problems for the Chief Clerk's Office that may prove difficult to resolve in the future and it may jeopardize the development and implementation of and electronic tariff filing system which is already underway. For these reasons, ComEd's request for a variance from the requirements of 83 Ill. Admin. Code 255.30(c) is denied. ComEd in its Reply Brief on Exceptions agreed to work with Staff on this issue.

33. MISCELLANEOUS RATE DESIGN ISSUES

Rate BES-R, BER-NRA, BES-NRB, and Rider VLR7 are just and reasonable and are approved.

IX. CUSTOMER CHOICE AND RETAIL SUPPLIER ISSUES

A. CLARIFICATION OF TARIFFS FOR POST-TRANSITION PERIOD

ComEd

[122] ComEd agrees to work with RESs to develop a summary of the switching rules for purposes of the RES Handbook. Alongi-McInerney Reb., ComEd Ex. 24.0 30:765 35:896.

CES

CES testified that ComEd's tariffs need to be clarified. CES appears to be satisfied with ComEd's offer to work with RESs to develop a summary of the switching rules for purposes of the RES Handbook.

Staff

In responding to CES' recommendation that ComEd modify or clarify the tariffs that were recently approved by the Commission in Docket No. 05-0159, Staff witness Schlaf testified that CES' comments are understandable since the new tariffs will have unfamiliar names, terms and conditions, and some current tariffs will not even exist after 2006. Dr. Schlaf recommended, however, that the Commission not require ComEd to modify the new tariffs for two reasons. First, he noted that over time the new tariffs will become familiar. Second, Dr. Schlaf testified that ComEd committed to modifying its RES Handbook and Customer Handbook, which should minimize customer confusion about the new tariffs. (ICC Staff Exhibit 20.0, p. 14)

Commission Analysis and Conclusion

****241** The Commission's review of the record suggests that there is no longer a contested issue and ComEd is directed to work with RESs to develop a summary of the switching rules for purposes of the RES Handbook. *See* Commission Analysis and Conclusion under-Timely Revision to RES Handbook.

B. GENERAL ACCOUNT AGENCY

ComEd

[123] ComEd agrees that CES' proposal confuses the duties and rights of a RES with that of a GAA, essentially treating the two entities***375** as synonymous, which ComEd contends is inappropriate and not in keeping with the Act or ComEd's tariffs. Crumrine Reb., ComEd Ex. 23.0 77:1673-79:1720; Meehan Reb., ComEd Ex. 26.0 4:92-7:153. Additionally, ComEd asserts that the proposal to create multiple agents that are ‘stacked‘ by both type of agency and effective date is problematic, from an operational perspective. Meehan Reb., ComEd Ex. 26.0, 8:154-59, 9:185-10:216; Meehan Sur., ComEd Ex. 43.0, 2:40-46, 3:52-54,. Finally, ComEd argues that the issues raised by CES are complex IT and business process issues that have statewide implications, and are more appropriate for a workshop forum than for a decision in this rate case. Crumrine Reb., ComEd Ex. 23.0, at 80:1721-32; Crumrine Sur., ComEd Ex. 40.0, at 83:1871-1908; Meehan Sur., ComEd Ex. 43.0, 4:74-93. ComEd notes that Staff concurred that the issues are more appropriate for workshops. Schlaf Reb., Staff Ex. 20, 13:291-14:307.

Staff

Staff witness Schlaf recommended that the Commission reject CES' recommendation that ComEd allow customers to: (1) choose the level of authority that General Account Agents (‘GAA‘) should be given and (2) designate multiple GAAs. (ICC Staff Exhibit 13.0, pp. 12-13) He noted that ComEd has cited operational reasons for not supporting the recommendation and has expressed concerns that an agent could resell ComEd's service without first receiving certification as an Alternative Retail Electric Supplier. (*Id.*) Dr. Schlaf agreed with ComEd's suggestion that discussion of GAA issues would be more appropriate in an informal workshop setting, rather than in the instant proceeding. (ICC Staff Exhibit 20.0, p. 13)

CES

CES requests that the Commission direct ComEd to revise both its General Account Agent (‘GAA‘) form and its business processes to clarify the options associated with customers' designation of a GAA. CES explains that ComEd's current process allows each customer to authorize an agent to receive the customer's ComEd bills and other ComEd correspondence, as well as to make energy supply decisions for the customer. (*See* CES Initial Br. at 21.) An ‘agent‘ may be an energy consultant or advisor, a relative, or a RES. In order to inform ComEd of the agency relationship, ComEd requires the customer to sign a GAA form and remit it to ComEd. According to CES, both the form itself and the manner in which ComEd processes the form unnecessarily inhibit customer choice. (*See id.*)

CES points out that ComEd itself has acknowledged that a customer typically switches its GAA when the customer changes its RES, and that the customer may prefer to authorize one agent to receive bills and other utility communications and to authorize another agent to analyze and select supply options on the customer's behalf. (Meehan, Tr. at 709-10.) CES requests that ComEd revise its practices and GAA form to better accommodate the realities of the Illinois retail electric market. (*See* CES Exs. 2.0 at lines 79-139, 6.0 at lines 64-125.)

****242** In particular, CES recommends that ComEd modify the form and operation of its GAA processes in three very specific and limited ways to:

•*Add an Effective Date* - According to CES, the inclusion of an effective date for the commencement of the agency relationship between the customer and the RES would solve many problems, yet CES argues that ComEd has failed to provide a legitimate rationale for exclusion of such a standard commercial term in the GAA form.

•*Permit Two Agents* - To clarify the type of agency authority granted by the customer to the GAA, CES recommends that the GAA form be revised to recognize what the customer is authorizing the GAA to do on the customer's behalf, such as receiving bills or arranging and managing tariff services on behalf of the customer.

•*Provide Limited Access to Former GAAs* - CES recommends that, in order to ***376** facilitate customer inquiries and resolution of billing disputes, ComEd should allow former GAAs to access the customer billing information generated when the agency was effective.

(*See* CES Exs. 2.0 at lines 241-52, 6.0 at lines 188-208; CES Initial Br. at 22.)

Background: The Development of the GAA Form

CES emphasizes that the concept of utilizing an ‘agent‘ to assist in dealings with a utility is neither new nor unique to the electric industry. (Meehan, Tr. at 708-09.) Well before the restructuring of the Illinois retail electric market, agents assisted customers with receiving and paying their utility bills. (*See id.*)With the advent of customer choice, commercial and industrial customers were presented with more options for electric service, and found it convenient to hire energy advisors and consultants. (Meehan, Tr. at 709-10.) To facilitate the interaction with ComEd, customers often made these advisors and consultants their agents, enabling the agents to act on their behalf to direct ComEd to switch the tariff under which they took service. (*See id.*)

CES notes that the Commission accepted ComEd's proposal to implement the use of a GAA form in ComEd's delivery services rate case. (*See* ICC Docket No. 01-0423, Interim Order at 151 (April 1, 2002); Meehan, Tr. at 734-35; CES Initial Br. at 23.) Now, customers who want to authorize an agent to obtain bills and remit payment, submit a GAA form signed by the customer, memorializing this relationship with the agent. (*See* CES Ex. 2.0 at lines 212-14, Meehan, Tr. at 718-23, CES Cross Ex. 5.0.) Similarly, customers can authorize an agent to analyze supply options and select the most appropriate tariff under which the customer is ultimately served. (*See* CES Ex. 2.0 at lines 215-16.) Again, the agent would inform ComEd of this authority by submitting a GAA form signed by the customer. (*See* CES Ex. 2.0 at lines 217-18; CES Initial Br. at 23.)

The Problems: ComEd's Current GAA Form and Related Business Processes

Based on CES members' significant experience working with both the form and ComEd's related business processes, CES highlights the problems associated with the current GAA form that ComEd uses. (*See* CES Ex. 2.0 at lines 231-39.) CES provided testimony regarding the customer confusion, frustrations, and inefficiencies that market participants have experienced as a result of ComEd's GAA form and business practices. (*See* CES Ex. 2.0 at lines 203-376, CES Ex. 3.0 at lines 270-322, CES Ex. 5.0 at lines 404-31, CES Ex. 6.0 at lines 187-284; CES Initial Br. at 23-26.) CES' witnesses explained that these problems will undoubtedly be magnified by the sheer volume of customers that may switch during the post-transition period. (*See* CES Ex. 2.0 at lines 288-94.)

****243** CES argues that the first problem is an unintended consequence resulting from the timeframe within which ComEd processes the GAA forms. (*See* CES Ex. 2.0 at lines 267-72.) ComEd's current practice is to change agency status ‘immediately‘ when the GAA form is received. (*See* ComEd Ex. 26.0 at lines 130-31.) CES observes that ComEd's definition of ‘immediately‘ apparently is a range of between three (3) to ten (10) days. (*See* CES Cross Ex. 5.0.)

According to CES, the most obvious resulting problem is that an agent can become the agent of record prematurely. (*See* CES Ex. 2.0 at lines 255-72.) Because the customer and agent cannot specify the date upon which the agency relationship is to become effective, CES states that ComEd may recognize a change in agency status prior to the customers' next regularly scheduled meter read date. According to CES, this results in ComEd sending invoices to the new RES, who is also acting as the new GAA, for service periods prior to the switch date. CES avers that sending invoices to the wrong GAA/RES causes customer confusion, delayed processing of invoices, delayed payments to ComEd and/or the incumbent supplier, and potential unintended adverse implications ***377** to the customers' credit standing with ComEd. (*See* Meehan, Tr. at 737-44; CES Ex. 2.0 at lines 255-62.)

CES argues that the second set of problems arises from ComEd's failure to allow customers to choose different agents to perform different functions. CES presented evidence that ComEd has recognized that customers use the GAA form not only with RESs, but also with other market participants, including energy advisors, brokers, and consultants. (*See* Meehan, Tr. at 707-10.) CES provided additional evidence to demonstrate that some of these market participants use the GAA form only to obtain invoices on behalf of the customer; others use it to authorize agents to make rate and tariff selections. (*Id.*) However, CES complains that ComEd's current form and business processes simply do not distinguish among different types of agency authorization. CES urges that as a matter of sound public policy and as a matter of law, the Commission should order ComEd to revise its use of the GAA form. (*See* CES Initial Br. at 24-25.)

CES maintains that as a matter of policy, ComEd's forms should not unnecessarily inhibit customers' ability to act in the competitive market. (*See* CES Ex. 6.0 at lines 187-284.) CES notes that even ComEd witness Meehan recognized that customers may want to have different agents performing different functions. (*See* Meehan, Tr. at 707-10.) Thus, according to CES, ComEd's GAA form and business processes preclude customers from exercising this choice.

CES makes the additional point that ComEd's current ‘one agency fits all‘ process results in frequent unintended GAA changes. (*See* CES Exs. 2.0 at lines 30415, 6.0 at lines 245-50.) For example, when a customer is asking for price quotes from multiple parties, each one of those parties may become the customer's GAA. If bills are sent to the wrong party, CES explains that customer confusion and billing problems inevitably result, and confidential information may also be inadvertently sent to the wrong party. (*See* CES Exs. 2.0 at lines 310-15, 6.0 at lines 245-64.) Most importantly, according to CES, ComEd's snafu may result in a customer missing an opportunity to effectuate a cost-saving rate change, if, for example, ComEd rejects a properly-designated agent's request for information. (*See* CES Initial Br. at 25.)

****244** CES asserts that, as a matter of law, customers cannot be precluded from having different agents perform different functions. (*See White Eagle Laundry Co. v. Slawek*, 296 Ill. 240, 243, 129 N.E. 753, 754 (1921) (finding that an individual has a contract right to appoint an agent to do anything that they may properly do themselves).) That is, according to CES, customers legally may designate one agent for some functions (*e.g.*, receive and pay bills), and authorize a different agent for other functions (*e.g.*, make tariff selections). (*See* CES Initial Br. at 25-26.)

Finally, CES highlights the problems associated with ComEd's failure to allow a customer's ‘former-GAA‘ to have access to information related to the time when the agency was in place. CES explains that a RES may need limited access to a customer's billing and payment information before or after the time a customer is served by that RES. (*See* CES Ex. 2.0 at lines 341-63; CES Initial Br. at 26.) For example, CES states that a RES may need to access this information prior to the service start date in an effort to clear up prior balances with ComEd on behalf of that customer. Also, CES provides a real-world example where a RES may need to access billing and payment information after its final service date in order to clear up outstanding issues that may have occurred with the RES' final bill or to clear up issues related to how ComEd applied payments made by the supplier on behalf of the customer. In these limited instances, according to CES, the RES is only requesting authorization to review billing and payment information in order to resolve these specific types of issues. Under the current process, however, CES avers that a previous supplier must re-request full agency rights (potentially ‘bumping‘ an existing agent) in order to access this information, then rescind its agency rights after the billing information is received. (*See* CES Ex. 2.0 at lines 360-63.)

****378** Commission Analysis and Conclusion*

CES wants the General Account Agency (‘GAA‘) form to be modified to add an effective date. According to CES, the inclusion of an effective date for the commencement of the agency relationship between the customer and the RES would solve many problems. CES has also proposed that ComEd be required to allow customers to: (1) choose the level of authority that General Account Agents should be given and (2) designate multiple GAAs. CES also recommends that in order to facilitate customer inquiries and resolution of billing disputes, ComEd should allow former GAAs to access the customer billing information generated when the agency was effective.

ComEd objects to essentially all of CES' proposals claiming, among other things, that they are inconsistent with the Act or ComEd's tariffs and confuse the rights and duties of RESs and GAAs. ComEd suggests the issues raised by CES would be better addressed in a workshop forum.

Staff recommends that the Commission reject CES' proposal that ComEd should allow customers to choose the level of authority that General Account Agents should be given and to designate multiple GAAs. Staff agrees that a workshop forum is appropriate for addressing CES' concerns.

****245** Based upon its review of the record, the Commission is not prepared to require that ComEd's GAA form be modified to include an effective date. While the Commission understands CES' assertion that such a requirement would mitigate certain problems for RESs, it also recognizes that this requirement would create problems for ComEd. The record indicates that ComEd would need to implement significant changes to its business practices and information technology systems to accommodate this proposal. The Commission is not willing to impose the burdens associated with CES' proposal because it's not clear that the benefits would exceed the costs.

The Commission next turns to CES' proposal that would allow customers to choose the level of authority that General Account Agents should be given and to designate multiple GAAs. The Commission finds that CES' assertion that, as a matter of law, customers cannot be precluded from having different agents perform different functions is simply not supported by the case cited. The Commission believes that ComEd's interpretation of that case, as stated in its reply brief, is more accurate than is CES' interpretation. While customers may have the right to an agent, CES has not demonstrated that customers have a legal right to multiple agents.

Additionally, CES suggests that ComEd prohibits customers from using different entities to perform different functions. The Commission does not believe that is the case. ComEd's business functions and processes sometimes make it somewhat difficult - but certainly not impossible - for customers to use multiple entities to perform different functions. While there is probably room for improvement in how ComEd accommodates different situations, the Commission is reluctant to adopt CES' proposal requiring ComEd to provide for different degrees of GAA or multiple GAAs. The Commission is concerned about the potential for abuse and confusion if multiple GAAs or different levels of GAAs are mandated. Additionally, the Commission cannot simply ignore the fact that such a proposal would impose costs and burdens on ComEd that would ultimately be borne by customers. Thus, CES' proposals in this regard will not be adopted.

With regard to CES' recommendation that ComEd allow former GAAs to access the customer billing information generated when the agency was effective, ComEd claims it is precluded by Section 16-122 of the Act from providing customer-specific information to a third party without the customer's authorization. ComEd effectively argues that Section 16-122 of the Act is intended to prevent the Company from indiscriminately disseminating customer billing and usage data. In reality, Section 16-122 is intended to compel ComEd into disseminating customer billing and usage data to certain entities. While Section 16-122 does contain provisions intended to protect consumers, the Commission believes ComEd has misstated the underlying purpose and meaning of Section 16-122 of the Act.

****246 *379** The Commission directs ComEd to allow former GAAs to access the customer billing information generated when the agency was effective for the purpose of facilitating customer inquiries and resolution of billing disputes relating to the time in which the agency was effective. ComEd is not required to provide billing and usage data to an entity that did not present verifiable authorization and was not acting as the customer's agent. The Commission finds this interpretation of Section 16-122 of the Act to be reasonable because the outcome is favorable to customers; is not burdensome to ComEd and; will advance the effectiveness of the competitive electric markets in Illinois. Thus, the Commission finds that this requirement is in the public's interest.

With regard to CES' proposals rejected in this Section of the Order, the Commission will accept Staff's and ComEd's suggestion that these issues be addressed in a workshop forum. The Commission directs Staff to initiate a workshop process that will focus on General Account Agency. The Commission directs Staff to begin the process within 60 days of the issuance of this Order and ComEd is directed to participate in a cooperative manner. The workshop process will focus on identifying what, if any, changes should be made to the role and responsibilities of agents. The workshop also will explore possible changes to ComEd's business practices and IT functions to accommodate GAAs. At the conclusion of the workshop process, Staff is directed to report the findings of the workshop process to the Commission. The Commission will then take additional steps deemed appropriate based on the workshop findings. To the extent the workshop process establishes that changes to ComEd's delivery services tariffs are needed, ComEd will make the appropriate tariff filings to implement these changes.

C. ELECTRONIC DATA INTERCHANGE

ComEd

124-126] ComEd contends that there is no demonstrable need for it to make significant alterations to its operations regarding Electronic Data Interchange (‘EDI‘) such as information providing electronic customer enrollment on ComEd's own products that require a ‘wet signature‘, listing of all active meters on an account at the time of sign-up, real-time drop notifications, the provision of additional account information, and alteration of the time in which a customer's bundled balance is checked for purposes of Rider SBO - Single Bill Option (‘SBO‘). Meehan Reb., ComEd Ex. 26.0, 12:255-20:426. ComEd cautions that CES' recommendations would grant GAAs access to the same EDI that are reserved for RESs.*Id.* Crumrine Reb., ComEd Ex. 23.0, 77:167379: 1720.), and suggests that any suggestions to modify EDI protocols be raised and discussed by market participants in the Communications Protocol Working Group (‘CPWG‘). Meehan Reb., ComEd Ex. 26.0, at 12:243-54; Meehan Sur., ComEd Ex. 43.0, at 5:105-6:128; Crumrine Reb., ComEd Ex. 23.0 at 80:1721- 1732. ComEd notes that, again, Staff concurs with ComEd's position. Schlaf Reb., Staff Ex. 20.0, 13:291-14:307.

****247** *Staff*

Staff witness Schlaf recommended that the Commission reject CES' recommendation that improvements be made to Electronic Data Interchange (‘EDI ‘) methodologies. (ICC Staff Exhibit 20.0, p. 14) He stated that the Commission has generally viewed the technical details of EDI transactions as matters that utilities and RESs should attempt to resolve informally. (*Id.*, p. 13) Utilities and RESs have established working groups to discuss EDI issues. (*Id.*) Thus, Dr. Schlaf concluded that CES' recommendations should first be discussed through the workshop process and should only be brought to the Commission's attention for resolution if the issues cannot be resolved informally. (*Id.*, pp. 13-14)

CES

CES asserts that customer choice simply would not work if everything were done via ‘hard copy‘ paper transactions. Thus, CES states that ComEd's use of EDI has greatly contributed ***380** to the success of the competitive energy market in Illinois. (*See* CE S Ex. 2.0 at lines 453-60.) CES notes that ComEd itself recognizes that using computers to interact with suppliers increases operational and administrative efficiency. (Meehan, Tr.

at 703.) As a result, according to CES, RESs receive most of the important day-to-day operational information from ComEd in the form of an EDI file or transaction, including: customer enrollments and disenrollments (or ‘drops‘), name changes, and meter changes. (*See* CES Ex. 2.0 at lines 382-99.) Nonetheless, CES argues that several simple, yet critical, improvements should be made to ComEd's EDI processes. (*See* CES Initial Br. at 28-30.)

CES makes three (3) recommendations regarding ways in which ComEd should expand the use of EDI processes and procedures. First, CES submits that systems that ComEd currently employs for RES customers should apply to customers that elect ComEd post-2006 bundled and PPO service. Second, CES argues that ComEd's EDI processes should be revised to efficiently and effectively handle customer name and taxpayer identification number changes. Third, CES maintains that EDI processes should be used to provide timely notifications of customer drops. CES highlights that it is not proposing any revision to ComEd's EDI certification processes or ComEd's EDI contract. That is, under CES' proposal, ComEd would continue to have EDI interaction only with RESs and the subset of GAAs whom ComEd certifies as being EDI-qualified. (*See* CES Ex. 2.0 at lines 104-39; CES Initial Br. at 29.)

CES asserts that its proposed revisions are designed to increase customer satisfaction, promote cost savings, and mitigate operational risks. (*See* CES Ex. 2.0 at lines 462-72.) According to CES, the switching statistics demonstrate that while the amount of the average load is much smaller, the number of customers enrolled on the PPO is almost three times greater than the number of customers enrolled on third-party service. Thus, according to CES, allowing RESs to process PPO customer enrollments using the EDI framework and instituting uniform processes and procedures for customer enrollment, regardless of the supply option chosen, will result in administrative and financial efficiencies for all involved parties. (*See* CES Ex. 2.0 at lines 462-72.)

****248** CES avers that ComEd refused to engage in a meaningful and constructive dialogue regarding CES' proposed EDI process revisions, once again suggesting that only the issues raised by ComEd are appropriate for consideration. (*See* ComEd Ex. 26.0 at lines 246-54.) CES argues that ComEd's inaction clearly dictates that the Commission should weigh in on these important operational issues, consistent with the Commission's statutory mandate to promote the development of an efficient and effective competitive retail electric market. (*See* 220 ILCS 5/16-101A(d).)

Utilization of EDI For Enrollment of PPO, CPP-A and CPP-B Customers

According to CES, ComEd currently uses a paper-intensive, manual process to enroll and dis-enroll PPO customers. (*See* CES Ex. 2.0 at lines 412-21; CES Initial Br. At 30.) That is, CES asserts, ComEd requires each customer to submit a ‘hard copy‘ enrollment form that ComEd does not convert into an electronic file. (*See id.*)Compared to the EDI process used for RES-supply customers, CES states that the inefficient, manual nature of the PPO process unnecessarily imposes operational risks and costs upon customers. (*See id.*)CES finds it surprising that ComEd intends to continue using a manual approach for customers to sign up for PPO service as well as bundled service under its post-transition period rates. (*See* ComEd Ex. 26.0 at lines 265-71; Meehan, Tr. at 704; CES Initial Br. at 30.)

According to CES, the current manual PPO enrollment and termination process involves unnecessary and inefficient paperwork, creating an unnecessary burden for customers during the existing 75-day enrollment window. (*See* CES Ex. 2.0 at lines 412-21; CES Initial Br. at 30.) According to CES, the shortened enrollment window of just 40 days ordered by the Commission in ICC Docket No. 05-0159-35 ***381** days less than the existing enrollment window - magnifies the inefficiencies and risks of manual processing, as customers, ComEd, GAAs, and RESs are forced to complete the manual enrollment process in a compressed timeframe. (*See id.*)

To begin the enrollment process, the customer must first give ComEd notice that the agent is authorized to act on the customer's behalf. (CES Initial Br. at 30.) This requires submission of a GAA form. (CES Initial Br. at 30.) Next, the agent must submit a PPO Contract form, but can do so only if the agent also submits a GAA form to ComEd for manual processing via facsimile. (*See* CES Ex. 2.0 at lines 427-37; CES Initial Br. at 31.) In order to terminate service under the PPO, at the end of the PPO contract term, a PPO Contract Termination form, which is a binding notice to terminate the PPO contract, must be submitted to ComEd via facsimile for manual processing. (CES Initial Br. at 31.)

Name And Taxpayer ID Changes

CES explains that under ComEd's current unwritten ‘policy,‘ if a customer changes its name or taxpayer identification number, then ComEd will ‘final‘ the existing account number and issue a new account number. (*See* CES Ex. 2.0 at lines 581-86; CES Initial Br. at 32.) In addition, CES states that if ComEd lacks a taxpayer identification number on file and a customer provides that information, ComEd will also ‘final‘ the account number and issue a new account number. (*See id.* at lines 586-89; CES Initial Br. at 32.)

****249** According to CES, ComEd's entire billing and usage system is driven by account numbers. (*See id.* at lines 591-606; CES Initial Br. at 32.) Therefore, CES presented evidence that if a retail customer was taking service under ComEd's PPO, and if someone in the customer's accounts payable department called to ask a billing question and volunteered a taxpayer identification number that was not previously on file, that retail customer would be summarily dropped from the PPO and would need to make new arrangements for electric supply. (*See id.*)

CES states that this situation is an obvious unintended consequence of ComEd's ‘policy‘ - which presently is not memorialized in any document - of determining whether to ‘final‘ an account number. (*See id.*)While the customer considers various supply options, CES explains that depending upon the customer's size and eligibility, the customer could be transferred to Rider ISS, bundled service, or Rate HEP. CES further explains that such a scenario would occur even if the customer were taking service at the identical physical service address and there had been no change in the customer's usage or demand, and even if there were no actual change in the customer's taxpayer identification number but rather ComEd just received one for the first time. (*See id.*)

Notification Of Customer Drops

CES asserts that ComEd has refused to implement uniform procedures and processes to timely inform RESs and GAAs when a customer account is to be terminated. In many instances, CES states that ComEd notifies the RES and GAA only *after* termination of a customer account. (*See* CES Ex. 2.0 at lines 502-13; CES Initial Br. at 33.) According to CES such untimely notice precludes RESs and GAAs from confirming that the customer account should be dropped, even though drops are often a result of ComEd's bureaucratic snafus described above rather than the result of customers' affirmative decisions. (*See id.*)

CES argues that ComEd's failure to provide timely customer drop information and notification causes immediate economic havoc to customers and RESs. Thus, CES asserts that customers may be precluded from selecting certain options (such as the PPO, if the error is discovered after the enrollment window is closed). (*See* CES Ex. 2.0 at lines 515-41; CES Initial Br. at 34.) Likewise, CES avers that RESs can be financially harmed as the load forecast and schedule, while submitted in good faith, included this customer account information. (*See id.*)Overall, according to CES, the increased operational risks and decreased efficiency***382** once again translate directly into increased costs for customers. (*See id.*)

Commission Analysis and Conclusion

Under CES' proposal, ComEd would continue to have EDI interaction only with RESs and the subset of GAAs whom ComEd certified as being EDI-qualified. CES' first proposed change is for the systems that ComEd currently employs for RES customers to apply to customers that elect ComEd post-2006 bundled and PPO service. Second, CES wants ComEd's EDI processes to be revised to better handle customer name and taxpayer identification number changes. Third, CES recommends that ComEd's EDI process be used to provide timely notifications of customer drops.

****250** CES claims that allowing RESs to process PPO customer enrollments using the EDI framework and instituting uniform processes and procedures for customer enrollment, regardless of the chosen supply option, will result in administrative and financial efficiencies for all involved parties. Compared to the EDI process used for RES-supply customers, CES asserts that the inefficient, manual nature of the PPO process unnecessarily imposes operational risks and costs upon customers.

ComEd claims that CES blurs the lines between RESs and GAAs. A RES does not send a PPO enrollment form on behalf of a customer. Rather, the prospective supplier sends a DASR to switch a customer to that supplier's service. In the case of CPP and PPO, ComEd is the supplier. The customer, or GAA acting on behalf of the customer, sends a written contract to ComEd to enroll a customer on PPO and a written notice to terminate PPO service. According to ComEd, this cannot be characterized as paper intensive. After receipt of the written contract, ComEd sends a DASR to itself, in the same manner that a RES would send a DASR for a customer to begin taking service from that RES.

CES claims it is too common that RESs receive notice from ComEd that an account has been ‘finaled‘ or dropped going back anywhere from 30 to 60 days prior to receipt of the notice. CES says such ‘retroactive‘ drop notices from ComEd, whether due to a name change or taxpayer identification number change, causes very real problems for the RES. CES contends that if the RES is not aware that an account has dropped out of service, the RES will continue to arrange for the supply of electric power and energy, forecast and schedule the anticipated usage, prepare an invoice to bill the customer, and attempt to collect payment for the services rendered. CES suggests that ComEd should provide RESs with a simple electronic notification when a drop is initially submitted. If a customer is to be dropped, then the RES should be notified at the same time ComEd is notified, not when the drop is processed.

ComEd claims that when a customer changes its name or taxpayer ID number, its system will consider this entity a new customer and final the existing account. The Company claims the issue is not its EDI system, but the definition of a customer for purposes of the system. In ComEd's view, it is neither workable nor appropriate to require ComEd to notify GAAs and/or RESs every time a customer takes action that modifies the customer information. However, ComEd says it is willing to modify the definition of a ‘new customer‘ so that an existing customer account is not ‘finaled‘ as a result of a name change.

CES suggests that customer account drops and other changes associated with the 814 EDI transactions, all drop information, including retroactive drops, should being provided to RESs electronically, in real time. ComEd claims its system is not capable of providing this information in real time. The Company states that all EDI transactions are produced at night in batch. A customer may change the service termination date many times and ComEd provides the drop information when the final bill is produced. ComEd believes this is appropriate and consistent with standard industry practice. However, ComEd says it is willing to provide information to RESs regarding pending disconnections through a weekly hard copy report.

****251** The Commission observes that while CES focuses on three specific proposals, its testimony seems to suggest it has more areas of concern. It appears that ComEd may have adequately***383** addressed some of the issues initially raised by CES. Many of the issues raised by CES are particularly difficult because they are outside the scope of routine electric utility regulatory issues.

CES' first proposal is for the systems that ComEd currently employs for RES customers to apply to customers that elect ComEd post-2006 bundled and PPO service. Having reviewed the record, it appears to the Commission that CES inaccurately implies that RES and GAAs are the same. The Commission understands that CES would like for PPO customers to be treated exactly the same as customers of alternate suppliers. Why CES suggests ComEd bundled customers should be treated like customers of alternate suppliers is more difficult to understand. Regardless, the Commission believes using CES' proposal as the basis for dictating how ComEd interfaces with its own customers, including PPO customers, is not appropriate. Contrary to CES' suggestion, this should not be central to improving the competitiveness of Illinois electric markets. The record shows that due to the differences between RESs and GAAs, CES' first proposal is simply not workable and is therefore rejected.

CES' second proposal is for ComEd's EDI processes to be revised in handling customer name and taxpayer identification number changes. This proposal appears to be related, at least in part, to CES' third proposal that ComEd's EDI process be used to provide timely notifications of customer drops. ComEd indicated its willingness to modify its processes so that an existing customer account is not 'finaled' as a result of a name change. While ComEd says it cannot provide notification of customer drops in the manner CES requests, the Company is willing to provide information to RESs regarding pending disconnections through a weekly hard copy report.

In the Commission's view, ComEd has made a good faith effort to accommodate CES on these issues. The Commission rejects CES' proposal to force ComEd to modify the manner in which it deals with changes in taxpayer ID. The record indicates that substantial information technology changes and costs would be necessary to accommodate this proposal. ComEd's proposal to modify the manner in which it deals with changes in names should mitigate CES' concerns. The Commission finds ComEd's practice of treating a change in taxpayer ID as creating a new customer reasonable.

Also, the record shows that ComEd cannot use its EDI to notify RES of customer disconnections as CES proposes. The Commission appreciates ComEd's willingness to provide information to RESs regarding pending disconnections through a weekly hard copy report. The Commission accepts this proposal and further directs ComEd to provide this list either through facsimile or electronic mail means to the RESs. The Commission believes this is a reasonable compromise that mitigates the concerns raised by CES but is not overly burdensome to ComEd.

****252** *See* the Commission Analysis and Conclusion under Weekly Pending Disconnect Report,

D. DATA EXCHANGE FOR POWERPATH

ComEd

ComEd explains that it provides RESs with access to usage data necessary for scheduling and/or billing purposes, and provides interval data reports and meter summary reports in a form that allows the variety of RESs operating in ComEd's service territory to analyze such data as they desire for each of their customers. ComEd asserts that CES' contention that RESs be allowed direct access to smart meters, which would grant RESs access to confidential usage data throughout ComEd's system, should once again be rejected, as it was in the Commission's Order in ICC Docket No. 99-0013 (Order dated October 4, 2000, pp. 68-74). Meehan Reb., ComEd Ex. 26.0, 21:465-22:79; Meehan Sur., ComEd Ex. 43.0, 6:130-7:153.

ComEd further notes that it provides relevant information to all RESs in the same format - one that permits a RES to easily sort the relevant data, in order to analyze the report to serve the RES' purpose with regard to a particular***384** customer. Accordingly, ComEd argues that CES' recommendation that ComEd be required to customize reports should also be rejected. Meehan Reb., ComEd Ex. 26.0, 22:480-23:502; Meehan Sur., ComEd Ex. 43.0, 7:154-8:175.

CES

CES states that the elimination of legacy bundled rates and the simultaneous introduction of new tariffs for bundled service and delivery service rates, in tandem with the attendant switching rules applicable to those rates and tariffs, necessitates that ComEd modify and/or supplement the PowerPath website so that customers and RESs easily may obtain the necessary information. (*See* CES Ex. 2.0 at lines 144-49; *see also* ComEd Ex. 26.0 at 439-43; CES Initial Br. at 35.) CES notes that

ComEd has agreed to implement the majority of CES' recommendations for revisions to PowerPath necessitated by the new market structure for the post-transition period. (*See* ComEd Ex. 26 at lines 33-41; CES Initial Br. at 35.)

Commission Analysis and Conclusion

CES claims that ComEd has refused to: (1) provide RESs and customers with read-only access to smart meters; (2) modify the content and format of the Interval Data and Meter Summary Reports; and (3) provide RESs with information necessary to facilitate customer enrollment under ComEd's Single Bill Option (‘SBO‘) tariff - Rider SBO7. CES contends that ComEd should modify PowerPath so that customers and RESs may obtain real-time information via the Internet.

ComEd states that it provides RESs with access to usage data necessary for scheduling and/or billing purposes, provides interval data reports and meter summary reports. This allows the variety of RESs operating in ComEd's service territory to analyze such data as desired for each of their customers. According to ComEd, CES' proposal to allow RESs direct access to smart meters, which would grant RESs access to confidential usage data throughout ComEd's system, should be rejected. This same issue was in the Commission's Order in Docket No. 99-0013. ComEd explains that the time at which it provides RESs with notice of bundled balances for SBO customers is based on the RESs request and that this provides the best opportunity for a customer to receive a single bill.

****253** The Commission has reviewed the record and rejects CES' request that RESs be granted direct access to smart meters. In the Commission's view, the meters in question are ComEd's meters and ComEd has certain obligations with respect to metering accuracy as well as maintaining the confidentiality of utility customer information. To the extent RESs need customer usage information, the Commission believes that adequate avenues currently exist for RESs to obtain necessary information. Finally, ComEd has explained that there are certain technical hurdles that would be difficult to surmount in order to fulfill CES' request and it is not entirely clear why CES believes access to these meters would be useful.

The Commission rejects CES' proposal that ComEd modify its interval data and meter summary reports. ComEd makes data available in a format that can be easily manipulated by any user that wishes to create customized reports. The Commission does not believe it is appropriate to require ComEd to create customized reports for RESs when the data in question is provided to RES in a manner that would allow each RES to create its own customized reports. For several reasons, including the cost that would be imposed on ComEd, the Commission believes that CES' request is unreasonable and unjustified.

Finally, the Commission rejects CES' request that ComEd provide RESs with information necessary to facilitate customer enrollment under Rider SBO7 on an accelerated basis. While the Commission understands the timing concerns raised in CES' testimony, CES seems to ignore the fact that its proposal would simply take time away from ComEd. In other words, any additional time provided to the RES by definition comes from ComEd. ComEd says five days is the minimum time that it needs to check for a past due balance and issue a dual ***385** bill, if necessary. This is an issue the Commission has previously addressed and CES has not adequately explained how its proposal represents an improvement over the existing arrangement.

The Commission again notes that CES raised additional issues in its testimony that were not addressed in either its brief or reply brief. The Commission concludes that either ComEd has adequately responded to these issues or CES has decided not to pursue them in this proceeding.

E. IMPROVED ELECTRONIC COMMUNICATION WITH CUSTOMERS/RESS

ComEd

ComEd notes that it established its business processes to provide clear, consistent information to customers and RESs, and segments its Customer Service Representatives ('CSRs') between business and non-business customers. The business CSRs are fully trained to address the issues raised by commercial and industrial customers and by RESs, and ensures that a CSR familiar with the concerns of business customers is always available. Additionally, ComEd indicates that its Electric Supplier Services Department ('ESSD') includes account managers, each of whom are assigned to particular large commercial and industrial customers and/or RESs, and can assist customers and/or RESs in resolving conflicts or clearing up any confusion that they may be experiencing. Meehan Reb., ComEd Ex. 26.0, 24:518-25:535.

CES

****254** CES makes a number of recommendations that would enable RESs to serve retail customers in Illinois, increase efficiency, ease data and information processing, and ensure that RES-supply service comports with ComEd-supply service. (CES Initial Br. at 35.) According to CES, ComEd has refused to: (1) provide RESs and customers with read-only access to smart meters; (2) modify the content and format of the Interval Data and Meter Summary Reports; and (3) provide RESs with information necessary to facilitate customer enrollment under ComEd's Single Bill Option ('SBO') tariff - Rider SBO7. (*See id.*)

Commission Analysis and Conclusion

The Commission believes that all contested issues related to electronic communications were addressed in the immediately preceding section of this Order.

F. UTILITY CONSOLIDATED BILLING WITH PURCHASE OF RECEIVABLES

ComEd

127-131] ComEd argues that it does not wish to offer the consolidated billing service, with or without a purchase of receivables option. ComEd notes that its current business processes and IT applications do not support utility consolidated billing. Meehan Reb., ComEd Ex. 26.0, 25:538-26:574; Meehan Sur., ComEd Ex. 43.0, 8:177-9:190. Furthermore, ComEd states that it is not in the third-party billing or 'bad debt' collection or insurance businesses, and is not interested in pursuing such businesses. Crumrine Reb., ComEd Ex. 23.0, 80:1734-81:1757; Meehan Reb., ComEd Ex. 26.0, 26:575-78; Meehan Sur., ComEd Ex. 43.0 at 9:191-203. ComEd criticizes CES for failing to demonstrate that UCB/POR would improve competition, and failing to acknowledge that potential statewide ramifications would need to be considered and thoroughly addressed before any UCB/POR proposal could be implemented. Crumrine Reb., ComEd Ex. 23.0, 81:1758-82:1783; Crumrine Sur., ComEd Ex. 40.0, Corr., 84:1910-86:1945.

ComEd notes that UCB service would constitute a new service under Section 16-103(e) of the Act, 220 ILCS 5/16-103(e), which ComEd cannot be compelled to offer. Crumrine Reb., ComEd Ex. 23.0, 81:1741-44. ComEd points out that Staff agrees that UCB/POR would represent a new service that ComEd cannot be compelled to offer and suggests that the propriety of any UCB/POR proposal should be discussed***386** in a workshop setting. Schlaf Reb., Staff Ex. 20.0, 10:216-12:261.

Staff

Staff witness Schlaf recommended that the Commission reject CES' proposed Utility Consolidated Billing ('UCB') service with a Purchase of Receivables ('POR') feature. (ICC Staff Exhibit 20.0, pp. 10-12) He noted that ComEd has argued that it: (1) does not believe that CES has demonstrated a persuasive enough business case to cause ComEd to incur the expenses that would be required to modify its billing systems to implement the proposal, and (2) cannot be compelled to offer the service, since the UCB program would constitute a new utility service. (*Id.*))
In its Initial Brief, Staff agreed with ComEd that ComEd cannot be compelled to offer the UCB program under Section 16-103(e) of the Public Utilities Act (the

'Act') (220 ILCS 5/16-103). (Staff IB, pp. 137-138)

****255** Staff argues that the UCB program is not a tariffed service required by Section 16-103 of the Act and it does not meet the definition of a competitive service under Section 16-102 of the Act (220 ILCS 5/102). While recognizing that the UCB program has the potential to interest RESs in serving smaller-use customers, Dr. Schlaf shared ComEd's concern that the cost of modifying its billing systems could be significant. (ICC Staff Exhibit 20.0, p. 11) Moreover, he was concerned that the POR feature of UCB might encourage RESs to market to customers that cannot meet their credit requirements because ComEd and its customers would be responsible for collecting delinquent payment from customers rather than RESs. (*Id.*) Finally, Dr. Schlaf stated that there is a possibility that Commission rules may have to be modified if a POR/UCB program were implemented. (*Id.*, pp. 11-12)

CES

CES asserts that its POR/UCB proposal for ComEd's CPP-B customers is good for consumers, good for competition, and good for ComEd. The Illinois General Assembly has directed that the Commission promote the development of the competitive market in a manner that benefits all consumers in Illinois. (*See* 220 ILCS 16-101A; CES Initial Br. at 36.) Toward that end, CES states that the Commission and ComEd must realize that systems will need to change in order to allow for the development of competition for small business and residential customers. (*See* ComEd Exs. 1.1, 1.2, 1.3; CES Initial Br. at 37.) CES believes that one of the most important elements of this transformation involves ComEd embracing improvements that will encourage competitive suppliers to enter the Illinois marketplace. (CES Initial Br. at 37.)

CES argues that its proposal sets forth the structure for a pro-consumer, pro-competitive POR /UCB program that will lower transaction costs, increase efficiency and minimize customer confusion. (*Seegenerally* CES Exs. 4.0, 7.0; CES Initial Br. at 37.) According to CES, ComEd apparently began considering the benefits of a POR / UCB program in 2002 (*see* Meehan, Tr. at 768) and it has since acknowledged that some means must be found to encourage suppliers to enter the market in order for residential competition to thrive. (Clark, Tr. at 204; CES Initial Br. at 37.)

UCB and POR Programs In Other Competitive Markets ComEd acknowledges the value of considering the experience of other states regarding the development of competitive residential markets in Illinois. (*See* Clark, Tr. at 204; CES Initial Br. at 37.) CES agrees with ComEd's strategy in this regard. CES, explains that most deregulated retail energy markets across North America have UCB programs, including ComEd's sister utility, PECO, and likely sister-to-be, PSEG, which both have POR /UCB practices in place. (*See* CES Exs. 4.0 at lines 65-69, 7.0 at lines 45-47; CES Initial Br. at 37.) According to ComEd's witness Meehan, ComEd and PECO representatives raised discussions of POR/UCB structures leading up to the companies' merger in 2000. (*See* Meehan, Tr. at 769; CES Initial Br. at 38.) CES suggests ***387** that Indiana and New York offer further examples of jurisdictions that have successfully implemented POR/UCB programs. (*See* CES Ex. 4.0 at lines 311-331, 349-86; CES Initial Br. at 38.)

****256** CES provides, as an example, that under PECO's UCB, PECO pays the retailer, known in Pennsylvania as the electric generation supplier ('EGS '), for the *undisputed* EGS charges PECO has billed the customer on behalf of the EGS, regardless of whether the customer has paid PECO. (*See* CES Ex. 4.0 at lines 71-79; CES Initial Br. at 38) Apparently, under the program, PECO or the EGS may request separate billing for accounts ninety (90) days or three billing cycles past due; PECO recovers the uncollectible amounts and program administration expenses through utility base rates. (*See id.*)PSEG likewise assumes supplier receivables and makes payment for the full undisputed supplier bill amount five (5) days after the due date on the customer bill. (*See id.*)

Similarly, CES highlights that the POR program for the Northern Indiana Public Service Company ('NIPSCO'), which is the only utility in Indiana offering competitive retail natural gas, has a POR program. (*See* CES Ex. 4.0

at lines 311-31; CES Initial Br. at 38.) Likewise, CES states that in New York, all New York utilities offer UCB in addition to a dual bill option and all but one utility regulated by the New York Public Service Commission (‘PSC‘) has adopted a POR program. (*See* CES Ex. 4.0 at lines 350-51; CES Initial Br. at 38-39.)

UCB/POR And The Development of Residential and Small Commercial Markets

CES argues that the implementation of CES' POR/UCB proposal would encourage the development of the competitive retail electric markets for residential and small commercial customers in Illinois. (*See* CES Ex. 4.0 at lines 112-19; CES Initial Br. at 39.) CES is proposing a POR/UCB program that would apply to the accounts of ComEd's delivery services customers with a peak demand below 400 kW (CPP-B customers) who receive a consolidated ComEd bill that includes both the delivery services provided by ComEd and the commodity of electricity provided by the RES. (*See id.* at lines 53-63; CES Initial Br. at 39.) Under CES' POR proposal, ComEd would purchase the RES' electric commodity service accounts receivable and any utility pass-through charges at a discount on the receivable's face value. However, under CES' proposal, RESs still would retain the right to offer the SBO, in which the RES bills for both the utility and RES charges, to any customer under the provisions of Rider SB07 regardless of the size of the customer. Thus, for RESs serving customers with demand less than 400 kW, ComEd would still be required to offer the following billing: SBO, UCB/POR, and a ‘dual-billing‘ model in which the RES may issue its own bill for its commodity charges. (*See* CES Ex. 4.0 at lines 58-60; CES Initial Br. at 39-40.)

According to CES, under UCB programs, the utility provides a single bill for its own charges as well as the RES' charges. A RES would electronically notify ComEd regarding the RES charges to be included on the bill. Under such a program ComEd would proceed with its regular billing and payment processing functions that it already performs for its bundled customers and then forward payment to the RES for its charges. (*See id.* at lines 81-90; CES Initial Br. at 40.)

****257** According to CES, under POR programs, the utility reimburses the RES for its customer billings regardless of whether the utility received payment from the customer. Further, CES notes that the utility is made financially whole by recovering the uncollectible amounts and program administration expenses through one of two options: (1) a discount rate equal to the utility's actual uncollectible amount that offsets the payments to the RES, and is subject to a periodic reconciliation process; or (2) an element of the utility's base rates. (*See* CES Ex. 4.0 at lines 44-51; CES Initial Br. at 40.) As noted, CES advocates the use of a discount rate, but either method can be used. (CES Initial Br. at 40.)

CES explains that under a POR program, customers benefit directly from increased ***388** access to competitive choices; and economies of scale are achieved by designating one party to handle all credit and collections and several consumer protection functions. (*See* CES Ex. 4.0 at lines 176-80; CES Initial Br. at 41.) According to CES, a POR program frees residential and small commercial customers from possibly having to post two separate security deposits and allows customers returning to service after having been terminated due to nonpayment to avoid having to contend with two payment plans. (*See id.* at lines 180-85; CES Initial Br. at 41.)

CES argues that encouraging RESs to accept all residential and smaller commercial customers - not just those with good credit scores - POR programs facilitate migration of customers who might be overlooked by RESs due to poor credit histories or past financial troubles. (*See* CES Ex. 4.0 at lines 187-90; CES Initial Br. at 41.) In addition, CES argues that utilities that implement POR programs avoid the problem of RESs serving the good credit customers, leaving the poor credit customers on utility service where they will escalate costs to all remaining bundled customers. (*See id.* at lines 198-203; CES Initial Br. at 41.)

RESs Benefit From POR/UCB Efficiencies

According to CES, a POR/UCB program in ComEd's service territory would create a level playing field for RESs to compete with ComEd; would result in a significant decrease in the cost for a RES to acquire customers; and would be accompanied by a potential market share increase resulting from more RESs being permitted to enroll mass market customers without conducting credit checks or requiring security deposits. (*See* CES Ex. 4.0 at lines 209-24; CES Initial Br. at 42.)

CES explains that currently, RESs in Illinois, unlike the utilities, lack the ability to terminate the physical delivery of electric or gas service to customers who do not pay the RES portion of their energy bill. (*See id.* at lines 210-13; CES Initial Br. at 42.) In contrast, if one of ComEd's bundled customers does not pay his bills, ComEd may disconnect the customer for both delivery and commodity. (*See id.* at lines 213-16; CES Initial Br. at 42.) As explained by CES, a RES faced with a nonpaying customer may only return the customer to bundled service and seek collection of the customer's arrears. As a consequence CES argues, all else being equal, ComEd's ability under the current structure to encourage payment through physical termination will always provide it with a lower uncollectibles rate compared to RESs. (*See id.* at lines 216-20; CES Initial Br. at 42.)

****258** Thus, CES argues that the lack of a POR program is a barrier to competition because it essentially creates a large segment of customers who are ineligible to participate in the competitive market. (*See* CES Ex. 7.0 at lines 124-38; CES Initial Br. at 42-43.) According to CES, bad debt can impose high costs upon RESs and although RESs typically screen customers to determine the customer's creditworthiness, it is not always feasible for customers to be credit screened during their first contact with the RES. (*See* CES Ex. 4.0 at lines 226-35; CES Initial Br. at 43.) Further, CES states that the credit checks add extra time to completing customer enrollment (*see generally* CES Ex. 4.3, 4.4; ComEd Ex. 10.7) and RESs must hire additional personnel to perform credit checks and pay a credit agency such as Equifax for credit reports. (*See generally* CES ex. 4.1, 4.2.) In short, uncollectibles represent a significant cost of doing business. (*See* CES Ex. 4.0 at lines 233-34; CES Initial Br. at 43.)

ComEd's Economic Efficiencies Through a POR/UCB Program

According to CES, ComEd has strong economic reasons to implement CES' proposed POR/UCB program. CES explains that Utilities that implement POR programs avoid the problem of RESs serving the good credit customers, leaving the poor credit customers on utility service where they will escalate costs to all remaining bundled customers. (*See* CES Ex. 4.0 at lines 201-3; CES Initial Br. at 43.) Further, under the proposed POR/UCB program ComEd would recover RESs' share of uncollectibles costs through a discount rate or through rate ***389** base, while recovering the costs for the risks associated with running the program from RESs. (*See id.* at lines 255-65; CES Initial Br. at 443-44.)

Commission Analysis and Conclusion

According to CES, a POR/UCB program in ComEd's service territory would create a level playing field for RESs to compete with ComEd. It would result in a significant decrease in the cost for a RES to acquire customers and would be accompanied by a potential market share increase. The market share increase would result from more RESs being permitted to enroll mass market customers without conducting credit checks or requiring security deposits.

ComEd criticizes CES for failing to demonstrate that UCB/POR would improve competition. ComEd also points out that potential statewide ramification would need to be considered and thoroughly addressed before any UCB/POR proposal could be implemented. ComEd argues that UCB service would constitute a new service under Section 16-103(e) of the Act, which the Company believes it cannot be compelled to offer. Staff agrees with ComEd that it cannot be compelled to offer the UCB program under Section 16-103(e) of the Act.

CES argues that it is not proposing POR/UCB as a ‘new service‘ but instead as a component of ComEd's delivery services that would be offered as a billing option. This would facilitate the entry of competitors for residential and small commercial customers. CES argues that it does not recommend that ComEd provide a new ‘bad debt‘ collection service. CES claims ComEd would continue to perform its own existing bad debt collection function. CES contends that the proposed POR/UCB program simply frees RESs from having to duplicate ComEd's existing billing and debt collection function.

****259** The threshold issues here are whether CES' UCB/POR proposals constitute new competitive services and whether ComEd can be forced to offer such services in light of Section 16-103(e) of the Act. Section 16-103(e) states, ‘The Commission shall not require an electric utility to offer any tariffed service other than the services required by this Section, and shall not require an electric utility to offer any competitive services.‘

The Commission finds CES' assertion that UCB/POR is not a ‘new service‘ but instead is a billing option that will become a component of delivery services difficult to accept. ComEd has been offering delivery services since October 1, 1999 but has never provided what CES now describes as a billing option component of delivery services. CES' position is untenable.

ComEd currently has a tariff in place, Rider SBO that allows an opportunity for RES to provide single billing services. The Commission believes that CES' UCB is the functional equivalent of single billing service. In the Commission's view, CES' UCB proposal would require ComEd to provide a new competitive service and under Section 16-103(e) of the Act, the Commission does not have authority to compel ComEd to provide such services.

As for CES' POR proposal, while the record is not well developed on this issue, the Commission would expect that there are opportunities in financial markets for entities to sell accounts receivable. In fact, on November 19, 1997 in Docket 97-0173 the Commission authorized MidAmerican Energy Company to enter into certain transactions that included the sale of accounts receivable. The Commission's Order in that proceeding suggests that the sale and purchase of accounts receivable is not uncommon. These types of transactions appear to take place largely in the absence of regulatory oversight and thus take place in a competitive market. Under 16-103(e) of the Act, the Commission does not believe that ComEd can be compelled to offer a service similar to CES' POR proposal.

The Commission will next briefly consider the merits of CES' proposal. Under CES' proposal a RES would essentially recruit customers, sign customers to contracts, arrange supply on behalf of customers, request that ComEd switch the customers and finally, wait for ComEd to send payments for supply. In other words, it appears that CES proposes to ***390** fully remove the RES from all billing and collection functions. The Commission understands why a RES may find such a proposal to be attractive. However, even assuming that the Commission had authority to order ComEd to implement CES' proposal, it is not clear that the proposal properly balances the interests of a RES, retail customers and ComEd. To implement CES' proposal would undoubtedly cause ComEd to incur significant costs that would ultimately be borne by ratepayers. Furthermore, the Commission is not convinced that CES' proposal would ultimately benefit Illinois' competitive electric markets. Therefore, this proposal of CES is rejected.

****260** *Modifications to Com Ed Business Processes to Aid RESs and Customers*

In response to issues raised by CES, ComEd agreed to make the following changes to its business processes:

• Eliminate the provision in proposed Rider SBO7 that precludes a Retail Electric Supplier (‘RES‘) from offering SBO service to a retail customer during the 12 monthly billing periods after it terminated such service. Crumrine Reb., ComEd Ex. 23.0, 70:1502-09.

• Change the definition of ‘new customer‘ so that an existing customer account would not be ‘finaled‘ (or closed and a final bill sent) as a result of a name change. Meehan Rebuttal, ComEd Ex. 26.0, 15:318-26; Clark/Witt Rebuttal, CES Ex. 6.0, 2:36-42.

• Amend to the Definitions part of ComEd's proposed General Terms and Conditions to provide clear definitions of the following terms: PJM Peak Period; PJM

Off-Peak Period; Retail Peak Period; and Retail Off-Peak Period.

• Revise its RES Handbook and its Customer Handbook, including development of a summary of the switching rules for purposes of this RES Handbook. Alongi/McInerney Reb., ComEd Ex. 24.0, 31:779-84.

• Amend the 12-month restriction in Rate RCDS as a one-time transition provision such that a customer could switch to delivery service on its last regularly scheduled meter reading date in 2006. Alongi/McInerney Reb., ComEd Ex. 24.0, 35:889-94.

• Post common RES questions and responses as FAQs on the PowerPath website. Meehan Reb., ComEd Ex. 26.0, 24:516-17.

• Make EDI 867 (detailed meter usage information) and 810 Billing Data (bill image of ComEd's delivery service bill) available electronically before 1:00 PM for same-day processing by RESs, and data submitted after 1:00 PM be dated the next business day.

• Provide information to RESs regarding pending disconnections through a weekly report. Meehan Reb., ComEd Ex. 26.0, 16:335-37.

• Provide current rate and supply-type information, including customer supply group and customer delivery class information, on ComEd's PowerPath website. Meehan Reb., ComEd Ex. 26.0, 20:439-43.

• Make information regarding DASR eligibility date available to requestors with proper authority, if such information is readily available. Meehan Rebut., ComEd Ex. 26.0, 21: 446-49.

• Provide time-of-use ('TOU') data relating to how ComEd defines peak and off-peak service for some customers, to RESs on the PowerPath website. Meehan Reb., ComEd Ex. 26.0, 21:459-64.

• ComEd Exhibits 10.0 and 10.8 described how each of the four Uncollectibles Adjustment Factors for each of the BES tariffs was determined. ComEd stated the record indicates that uncollectible expenses are properly allocated between electric supply and delivery customers. Crumrine Reb., ComEd Ex. 23.0, 54:1144-56.

ComEd and CES have made some progress during this proceeding to remove some of the obstacles to the robust implementation of retail competition. But, as the record clearly shows, there are still a number of obstacles that still need to be removed.

****261** The General Assembly charged the Commission ***391** with the obligation to promote retail competition. The PUA states that 'the Illinois Commerce Commission should act to promote the development of an effectively competitive electricity market that operates efficiently and is equitable to all consumers.'220 ILCS 5/16- 101A(d). Now is the time for the Commission to seriously assume the responsibility to promote retail competition. On January 2, 2007 retail electric customers in Illinois will begin to take energy that will be procured through an auction process through their local distribution company. To date there has only been one RES who has sought and received authority to serve residential and small commercial customers. For competition to be successful there needs to be more than one RES in Illinois providing a variety of services to the mass market customers. That Commission needs to take the appropriate steps to encourage more RESs to enter the Illinois market, especially to offer choices to the mass market customers.

In Docket No. 05-0159 and Docket Nos. 05-0160/05-0161/05-0162 (Cons.), the Commission ordered the initiation of a workshop process to evaluate the status of retail competition. The Commission staff recently completed the first phase of the project. While Staff and participants have made progress in meeting the objectives of the Retail Competition Workshop, it is now time to escalate the matter to a higher level. The Commissioners will assume responsibility for Phase 2 of the Retail Competition Workshop. The goal for Phase 2 is to develop concrete recommendations, using issues discussed in this proceeding as a basis, to present to the members of the Commission prior to October 15, 2006. From the positions presented by parties in this proceeding it appears that there are some legislative obstacles to promoting retail competition in Illinois. If true, the PUA will need to be amended to enable the Commission to meet its responsibility to promote retail competition.

X. STAFF REPORTS ON COMED'S PERFORMANCE

A. TREE TRIMMING

ComEd

132-135] ComEd observes that Staff's September 27, 2005 report on vegetation management (Exhibit A to the Reliability Assessment and introduced by Staff witness James Spencer) noted significant improvement in ComEd's tree trimming program, while also identifying areas for further improvement and certain areas requiring additional attention. ComEd states that it has already taken several steps - and has planned several others - to address Mr. Spencer's recommendations that ComEd (1) investigate certain problem areas regarding compliance with National Electric Safety Code Rule 218 (‘Rule 218‘) and consistency in tree trimming, (2) resolve certain identified tree clearance problems as soon as possible, and (3) assure that it meets the requirements of Rule 218 throughout its service area. Staff Ex. 9.1, at 10. As an example, ComEd points out that it has already addressed or developed a plan to address the vegetation issues at each of the 140 individual locations that Mr. Spencer identified as needing attention. Costello Reb., ComEd Ex. 13.0 Corr., 38:859-65 - ComEd also notes that more generally, it has been following a four-year tree-trimming cycle, with mid-cycle trims, and has undertaken various efforts to continue bettering its vegetation management performance.*Id.*

****262** *Staff*

Although Staff is not requesting that the Commission make a specific finding in this rate case, or order ComEd to take specific actions, Staff has submitted testimony explaining that Staff has concerns regarding ComEd's tree trimming. Staff asserts that ComEd is not in compliance with National Electric Safety Code (‘NESC‘) Rule 218, which the Commission has made a part of its Administrative Code Part 305. (ICC Staff Exhibit 9.0, pp. 6-7; ICC Staff Exhibit 10.0, Attachment 10.0, pp. 10-11) This is supported by testimony of Staff witness Spencer and *Staff's Assessment of ComEd's Reliability Report and Reliability Performance for 2004* (‘Staff Report‘). Staff notes that it has ***392** recommended to ComEd that the Company investigate its problem areas, take steps to correct those areas and prevent recurrence of the problems. (ICC Staff Exhibit 9.0, pp. 6-7). Staff states that if ComEd is found to be still be out of compliance after the tree trimming inspections in 2006, Staff has assured the Commission that it will take the actions necessary to ensure ComEd's compliance with Commission rules governing tree trimming.

Commission Analysis and Conclusion

Although Staff is not requesting that the Commission make a specific finding in this rate case, or order ComEd to take specific actions, Staff has submitted testimony expressing concerns regarding ComEd's tree trimming. The Commission recognizes the significant improvements that ComEd has made in its tree-trimming program, and encourages ComEd to continue that trend. Staff will continue with tree trimming inspections in 2006 and has assured the Commission that it will take the necessary action to ensure ComEd's compliance with Commission rules governing this area. The Commission finds Staff's recommendations for further improvement generally sound, and directs ComEd to continue to address these recommendations.

B. RELIABILITY PERFORMANCE

ComEd

ComEd observes that Staff's Reliability Assessment recognized, among other things, significant improvements and the strong overall trend in ComEd's reliability and service. ComEd notes several examples cited by Staff, which included substantial improvements in customer surveys, fewer complaints, significant numbers of customers experiencing no interruptions, and new corrective maintenance efforts. Stutsman Dir., Staff Ex. 10.0, Att. 1, pp. 7, 8, 29; *see* Stutsman, Tr. at 1762:22-1763:8). ComEd also notes that it agrees with the Reliability Assessment's recommendations - that ComEd (a) continue focusing on improving customer service, (b) continue improving its vegetation management program and address Staff's concerns, and (c) inspect and modify where needed insulating oil levels of substation equipment. (Staff Ex. 10.1, 30 - and had already addressed or begun to address each of them. For instance, ComEd provided evidence that it has been working to improve customer service in many ways, such as promoting a ‘customer-centric‘ culture, training its employees on guidelines for interacting with customers in positive ways and focusing on the importance of customer satisfaction. ComEd also notes its continuing efforts to respond better to storms, and its work to improve worst-performing circuits. Additionally, ComEd points to its plan to continue focusing on customer service in the future, as customer satisfaction will continue to be one of ComEd's strategic focus areas.*Costello Reb., ComEd Ex. 13.0 App. 2:960-79.*

Staff

****263** Although Staff is not requesting that the Commission make a specific finding in this rate case, or order ComEd to take specific actions, Staff has submitted testimony explaining that Staff has concerns regarding ComEd's maintenance, vegetation management, operations of substation equipment and customer satisfaction performance. Staff has already notified ComEd that it needs to improve its efficiency and economies of overall system maintenance and operation, and to inspect its substation equipment and make adjustments as necessary.

The basis of Staff's findings is *Staff's Assessment of ComEd's Reliability Report and Reliability Performance for 2004* (‘Staff Report‘). (ICC Staff Exhibit 10.0, Attachment 10.1) The Staff Report is prepared pursuant to 83 Illinois Administrative Code Part 411.140. The report is based on Staff's review of ComEd's 2004 annual reliability report and field inspections of trees, random circuits, worst circuits and substations that Staff conducted in 2005. The Staff Report culminates with *Potential Reliability Problems and Risks.* It is those problems and risks that Staff is emphasizing in this case.

****393** C. VEGETATION MANAGEMENT NEEDS IMPROVEMENT*

Staff recommends that ComEd continue improving its vegetation management program. (ICC Staff Exhibit 10.0, p. 8) When asked if it would take more resources on ComEd's behalf to do that, Staff replied that it could take either more resources or reallocate existing resources or just perform the work more efficiently. (Tr., p. 1768) Staff notes in its Staff Report that it is unconvinced that ComEd has sustained a four-year trim cycle at a level of reasonable quality. (ICC Staff Exhibit 10.0, Attachment 10.1, p. 30; Tr., p. 1768) Furthermore, it is absurd that ComEd had no concept, in mid-2005, of the magnitude of money it would be spending in 2007 on its vegetation management activities. (ICC Staff Exhibit 10.0, Attachment 10.1, p. 26) This lack of control is another indication of the volatility of ComEd's current vegetation management program.

Commission Analysis and Conclusion

Staff has indicated that many improvements are needed in ComEd's current vegetation management program. Staff is not sure if ComEd needs to perform the work more efficiently or if it needs more resources or if there is a need to reallocate existing resources. Staff remains unconvinced that ComEd has sustained a four-year trim cycle at a level of reasonable quality. Furthermore, Staff is concerned that ComEd had no concept of the magnitude of money it would be spending in 2007 on its vegetation management activities. The Commission agrees with Staff's recommendation that ComEd continue improving its vegetation management program. The Commission further directs Staff to advise the Commission if these problems continue in this area.

D. SUBSTATION EQUIPMENT

Staff recommends that ComEd inspect insulating oil levels of substation equipment as appropriate and make adjustments as necessary. (ICC Staff Exhibit 10.0, p. 8) When asked about the implication of insufficient oil levels in substation equipment, Staff observed that especially in small oil volume devices, such as bushings of oil circuit breakers, a catastrophic failure could result. For example, it could cause an event, much like an explosion, that would take out the breaker and spread burning oil throughout the substation yard. (Tr., p. 1767)

Commission Analysis and Conclusion

****264** Staff recommends that ComEd inspect insulating oil levels of substation equipment and make adjustments as necessary. Staff points out that insufficient oil levels in substation equipment can result in catastrophic failures. For example, it could cause an event, much like an explosion, that would take out the breaker and spread burning oil throughout the substation area. The Commission directs ComEd to follow the recommendations of Staff in this area.

E. CUSTOMER SATISFACTION PERFORMANCE

While Staff and ComEd are in agreement that ComEd has improved customer satisfaction performance over the last few years (Tr., p. 1763), Staff notes that since last year, ComEd is scoring in the neighborhood of other state utilities and even exceeded the scores of several other utilities in residential (but not commercial) customer satisfaction surveys. (ICC Staff Exhibit 10.0, Attachment 10.1, p. 7-8) Staff continues to recommend that ComEd continue its focus on improving customer service. (ICC Staff Exhibit 10.0, p. 8)

Commission Analysis and Conclusion

Staff and ComEd are in agreement that ComEd has improved customer satisfaction performance over the last few years. In the last year, ComEd scored in the neighborhood of other state utilities and even exceeded the scores of several other utilities in residential (but not commercial) customer satisfaction surveys. The Commission agrees with Staff in recommending***394** that ComEd continues to focus on improving customer service.

F. MAINTENANCE PROGRAMS

Staff asserts that adequate preventive and corrective maintenance programs, which include a well planned vegetation management program, are the most important factors to influence long-term customer reliability. Staff notes that unfortunately, maintenance programs are one area where a company can cut spending quickly and have an immediate impact on short-term income statement performance with minimal impact on short-term reliability performance. (ICC Exhibit 10.0, Attachment 10.1, p. 28) Staff points out that ComEd needs to strive for and invest in greater efficiencies *or* reallocate its resources *or* increase spending. (Tr., p. 1770) In addition, Staff observes that ComEd has improved its efficiency on corrective maintenance work, at least on a short-term basis, with a smaller manpower budget.

Staff, however, remains concerned that if efficiency improvements should plateau and/or workforce levels decline too far and/or maintenance budgets are not adequate, then ComEd would have a strong incentive to cut back on the intensity of inspections in order to reduce the backlog of corrective maintenance work. Staff continues to encourage ComEd to improve efficiencies and economies of maintenance and operations. (ICC Staff Exhibit 10.0, Attachment 10.1, p. 28)

Commission Analysis and Conclusion

Staff notes that ComEd has improved its efficiency on corrective maintenance work, at least on a short-term basis, with a smaller manpower budget. Staff points out that ComEd needs to strive for greater efficiencies and continue to invest in its maintenance program. Adequate preventive and corrective maintenance programs, which include a well planned vegetation management program, are the most important factors to influence long-term system reliability. Staff, does not want ComEd to cut back on the intensity of inspections in order to reduce the backlog of corrective maintenance work. The Commission agrees with Staff in encouraging ComEd to continue to improve the efficiencies of its maintenance and operation programs.

G. WORST CIRCUIT PERFORMANCE

****265** The poor performance of ComEd's worst-circuit in relation to the worst-circuit of other jurisdictional utilities for 2004 remains a matter of concern for Staff. (ICC Staff Exhibit 10.0, Attachment 10.1, p. 28)

Commission Analysis and Conclusion

The Commission notes Staff's concern for the poor performance of ComEd's worst-circuit in relation to the worst-circuit of other jurisdictional utilities for 2004. The Commission encourages ComEd to work towards improving in this area. Staff is directed to advise the Commission if this poor performance persists.

H. ELECTRIC METERING

ComEd

ComEd noted Staff's conclusion in its Meter Shop Inspection Report that, with four exceptions, ComEd's metering practices conform with the metering requirements of 83 Ill. Adm. Code Part 410. With respect to those four exceptions - namely, 1) certifying that all meter installations meet Section 4.7 of ANSI C12.1-1995 standards; 2) meeting post-installation inspection requirements; 3) when performing meter tests more than 30 days after a customer request, showing that the customer agreed to the delay; and 4) calculating properly billing adjustments for meters found to be inaccurate - ComEd states that it agrees with, and has acted on, each such area, except regarding the application of certain installation standards to certain older meters (for which ComEd was planning to file with the Commission a petition seeking a clarification or exemption). *Costello Reb. ComEd Ex. 13.2.*

ComEd also notes that it was already taking steps to implement Staff's recommendations,***395** which included 1) developing more accurate descriptions of the reasons for each meter test; 2) identifying whether meter tests are for sample testing, periodic testing, or testing at customer request; 3) adopting a method to demonstrate more readily that it is meeting periodic testing requirements; 4) ensuring that employees involved in billing adjustments understand and can respond to meter creep; and 5) refining its self-audit process to verify billing adjustments.*Costello Reb., ComEd Ex. 13.0 App., 18:1315-31. (Rockrohr Dir., Staff Ex. 11.0, Sch. 11.1).*

In addition, ComEd points to Staff witness Greg Rockrohr's testimony that the steps to which ComEd had agreed were reasonable and appropriate, and that such activities 'would resolve the issues that Staff found.' (Rockrohr, Tr. 1642:11-13. ComEd also notes Mr. Rockrohr's acknowledgment that these were not activities that ComEd had in place at the time of the Meter Shop Inspection Report (Rockrohr, Tr. 1642:1417), and that, to the extent the recommendations require work not previously performed, ComEd would require additional resources (Rockrohr, Tr. 16439-17), for which there might be additional costs. (Rockrohr, Tr. 1645:13-1646:1.

Staff

Although Staff is not requesting that the Commission make a specific finding in this rate case, or order ComEd to take specific actions, Staff has submitted testimony explaining that Staff has concerns regarding ComEd's electric metering. Staff based its findings on the most recent electric metering audit it performed, in which Staff found ComEd's electric metering practices out of compliance with the Commission's electric metering rules in four specific areas. (ICC Staff Exhibit 11.0, pp. 2-3, and Schedule 11.1 - Letter to ComEd RE: Staff's 2005 Electric Meter Shop Inspection, pp. 1-2) In testimony, Staff reviewed five recommendations it provided ComEd in December 2005 that were intended to help the Company more fully comply with the Commission's rules. (ICC Staff Exhibit 11.0, Schedule 11.1, pp. 3-4) Of Staff's findings and recommendations, the need for ComEd to comply with 83 Illinois Administration Code 410.120(e) is the only issue meriting discussion in this proceeding. (ICC Staff Exhibit 11.0, Schedule 11.1, p. 1) Staff asserts that ComEd does not agree with Staff's finding concerning Subsection 410.120(e).

****266** Subsection 410.120(e) requires 'meters installed after January 1, 2001 shall, at a minimum, meet the standards set forth in Section 4.7 of the American National Standards Institute's (ANSI) Code for Electricity Metering. ‘ In its audit, Staff found that ComEd does not install meters in compliance with Subsection 410.120(e), and that ComEd has not received a modification or exemption regarding Section 410.120***396** (e). Since a modification or exemption has not been granted to ComEd, Staff assures the Commission that it will continue its oversight of ComEd's metering practices and take the action necessary to ensure compliance with Commission rules.

Commission Analysis and Conclusion

Although Staff is not requesting that the Commission make a specific finding in this rate case, or order ComEd to take specific actions, Staff has submitted testimony expressing concerns regarding ComEd's electric metering. Staff based its findings on the most recent electric metering audit it performed, in which Staff found ComEd's electric metering practices out of compliance with the Commission's electric metering rules in four specific areas. The only issue meriting discussion in this proceeding is the need for ComEd to comply with 83 Illinois Administration Code 410.120(e). Staff asserts that ComEd does not agree with Staff's finding concerning Subsection 410.120(e).

Subsection 410.120(e) requires ‘meters installed after January 1, 2001 shall, at a minimum, meet the standards set forth in Section 4.7 of the American National Standards Institute's (ANSI) Code for Electricity Metering.‘ In its audit, Staff found that ComEd does not install meters in compliance with Subsection 410.120 (e), and that ComEd has not received a modification or exemption regarding Section 410.120 (e). Since a modification or exemption has not been granted to ComEd, Staff assures the Commission that it will continue its oversight of ComEd's metering practices and take the necessary action to ensure compliance with Commission rules.

The Commission finds Staff's recommendations and ComEd's efforts to address them, including additional expenditures needed for such efforts, prudent and reasonable. The Commission does note, however, the exception to ComEd's response regarding the application of certain installation standards of older meters. The Commission plans to address that issue in a separate proceeding.

XI. RESPONSES TO COMMISSIONERS QUESTIONS RELATING TO DEMAND RESPONSEComEd

[136] On March 16, 2006, Commissioners Lieberman and Ford issued a set of questions relating to the potential for additional demand response initiatives. Some of the issues raised by this set of questions have been fully discussed in previous sections of this Order. These include the use of the highest 30-minute demand for electric power and energy established during the monthly billing period (*i.e.* a 24-hour demand) for certain demand-based tariff charges (*see* discussion *supra* at Section II.I.22), meter costs applicable to residential RTP (*see* discussion *supra* at Section II.I.27), and the residential RTP program proposed by CUB (*see* discussion *supra* at Section II.I.27). Those discussions are not repeated here.

****267** ComEd comments on efforts in Illinois to provide demand response programs to consumers. First, ComEd indicates that Illinois has been a national leader in mandating forms of RTP for all customers. Second, ComEd notes that the Commission's approval of an hourly energy pricing default service for the largest customers in the procurement rider proceeding was consistent with the recommendations of the Department of Energy (‘DOE‘) issued in response to the 2005 amendments to the Energy Policy Act of 2005 (‘EPACT‘). U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them* (Feb. 2006) (‘ *DOE Report* ‘). Third, ComEd pointed out that it has offered three tariffs in this proceeding that incorporate demand response components (Riders AC7, VLR7 and CLR7).*Alongi-Crumrine, Sup. Rep., ComEd Ex. 96.0, 4:72-84* ComEd states that further investigation is needed to determine the benefits and costs of implementing additional programs. ComEd notes that despite general agreement that certain demand response programs could provide net benefits to customers and to the system, no party was able to quantify the benefits associated with any specific new demand response program, and all agreed that the methodologies that would be used to evaluate such benefits were not sufficiently defined. ComEd indicates that how such benefits are defined, how they should be monitored, and how the resulting data is to be evaluated, are all areas that require additional analysis and discussion among interested entities, as confirmed by the *DOE Report. Alongi-Crumrine, Sup. Rep., ComEd Ex. 46.0. 8:160-12:255*

Staff

In a letter dated March 16, 2006, Commissioners Ford and Lieberman submitted a list of questions to the Administrative Law Judges (‘ALJs‘). (‘Commissioners' Questions‘) regarding the topic of demand response and other topics. These questions seek comment on the findings and recommendations of research reports that analyze various demand response issues. The research reports include: (1) a report submitted by the Department of Energy (‘DOE Report,‘) to the U.S. Congress and (2) a report from the International Energy Agency (‘IEA ‘) entitled ‘DRR Valuation and Market Analysis‘ (‘IEA Report‘).

Further, the Commissioners' Questions seek comment on a policy statement contained within the Energy Policy Act of 2005 (‘EPAct‘). Other questions concern Staff's proposed real-time pricing pilot program, especially how Staff's proposed program relates to ***397** the ongoing real-time pricing program operated by the Community Energy Cooperative. Real-time pricing issues are discussed in Section IV.F.27. Finally, Staff provided input regarding the benefits to the system if the incentives to large industrial customers are sufficient enough to cause the customer to shift their load from peak periods to non-peak periods.

DOE Report

Staff witness Schlaf testified that the DOE Report, which was submitted to Congress in February 2006 in response to Section Sec. 1252(d) of EPAct, provides an overview of demand response programs in the United States, with a focus on the potential benefits of the introduction of demand response programs. He stated that the potential benefits of a given program, which may include ‘participant financial benefits,‘ ‘market-wide financial benefits,‘ ‘reliability benefits‘ and ‘market performance benefits,‘ depend on numerous factors, including assumed participation rates, customer interest and responsiveness to available programs, and local market characteristics. (ICC Staff Exhibit 22.0 Corrected, p. 3)

****268** Dr, Schlaf noted that the DOE Report also discusses the costs of demand response programs, which the report classifies as ‘participant‘ costs and ‘system‘ costs. The net benefits of demand response programs cannot be evaluated without an estimate of these costs. However, the DOE Report notes that there does not appear to be a consensus on a standard to evaluate the net benefits of the various types of demand response programs, and the report recommends that interested parties undertake a collaborative effort to establish standard evaluation methods. As a result, the DOE Report does not provide an estimate of the potential national benefit of the widespread implementation of demand response programs. (*Id.*, pp. 3-4)

The DOE Report offers several findings and recommendations. Dr. Schlaf's commented on the feasibility of applying each finding/recommendation to the ComEd service area. (ICC Staff Exhibit 22.0 Corrected, pp. 6-11; Staff IB, pp. 146-147)

IEA Report

Dr. Schlaf also testified about the IEA Report, focusing on the different types of methodologies that are used to estimate the value of incorporating demand response resources (‘DRR‘) into a resource portfolio. In one type of methodology, an attempt is made to determine what the value of DRR was after it was added to a resource portfolio, while other seek to determine the benefits of adding various types of DRR in resource portfolios. Yet other studies evaluate the reliability effects of adding DRR to a resource portfolio. (ICC Staff Exhibit 22.0 Corrected, p. 15)

Dr. Schlaf noted that the IEA Report concludes that certain types of DRR would be cost-beneficial under most conditions, including the following: 1) ‘mass-market direct load control of appliances that can provide load relief in a matter of minutes;‘ 2) ‘under-frequency relays installed on specific equipment that will be tripped the second voltage drops to unacceptable levels;‘ and 3) ‘large customer interruptible programs where several hours' notice may be required.‘ (IEA Report, p. 4) Dr. Schlaf noted that ComEd has already adopted the first and third types of DRR from this list. (*Id.*, pp. 15-16)

Dr. Schlaf stated that the IEA report explains that a shorter-term analysis the impacts of adding to DRR to a portfolio can employ the type of cost-benefit models that are have been often used to evaluate the cost-effectiveness of demand-side management programs. The IEA Report notes that most DRR evaluation studies use a variation of this methodology. For example, the State of California studied critical peak pricing programs using this methodology, as did some Wisconsin utilities when conducting an evaluation of TOU rates. Dr. Schlaf noted that results of Staff's pilot program could be analyzed using this type of cost-benefit approach. (*Id.*, pp. 17-18)

EPAct Policy Statement

Dr. Schlaf also testified with respect to the policy statement in Section 1252(f) of the ***398** EPAct which is quoted in the Commissioners' letter. The Commissioners' Questions seek comment concerning: (1) how CUB's proposed pilot program would further policy and (2) how Illinois should recognize and value the benefits described in this Section.

****269** Dr. Schlaf noted that ComEd proposes to offer Rate BES-H, an hourly-based rate, to all customer classes, including the residential class. In order to take this rate, a residential customer would have to lease a meter that is capable of recording hourly usage (*i.e.*, an IDR meter). While the cost of an IDR meter might be insignificant in comparison to the total cost of a large customer's bill, incremental leasing charges would constitute a fraction of a small customer's electric bill. Dr. Schlaf stated that the CUB proposal would require all residential customers to pay for a residential customer's meter, and therefore the CUB proposal would facilitate the introduction of RTP to residential customers. (ICC Staff Exhibit 22.0 Corrected, p. 13)

Dr. Schlaf noted the excerpt from EPAct appears to state that the benefits to nonparticipants of moving some customers to RTP should be recognized. Dr. Schlaf stated that while such a policy may generate nonparticipants benefits, a *net benefits* analysis should be conducted prior to implementation of a program that directly benefits participating customers only. (*Id.*, pp. 13-14)

Real-time Pricing/Energy Smart Pricing Program

See the discussion at Section IV.F.27.

24-Hour Maximum Kilowatts Delivered (‘MKD‘)

Staff

Commissioners Lieberman and Ford posed questions to the parties regarding ComEd's proposal that the billing demand for certain demand-based rates be based on the highest 30-minute demand during the monthly billing period (*i.e.*, 24 hour demand period). The first set of questions staff witness Mr. Lazare responded to concern the impact of moving load to non-peak periods. The questions were as follows:

From a system-wide perspective what are the benefits from incenting large industrial customers to switch their load to non-peak times (*i.e.*, reducing load on distribution system, reducing peak energy consumption, etc.)? IIEC Witness Stephens talks about the beneficial impact of off-peak operation by customers on network distribution facilities.

• Could the parties please comment in greater detail on these associated benefits?

• Please present evidence to substantiate your comments. (p. 5) and

• We know that there is value to improving the distribution load profile. ComEd is arguing that there is no benefit to incent that in their rates. Please comment as to whether there are benefits to the distribution company in terms of avoided cost related to flattening the load. Please discuss.

Staff witness Lazare explained that the system stands to substantially benefit from incentives that successfully cause large industrial customers to shift loads to non-peak hours. Staff argues that these benefits are reflected in the assumptions of ComEd's own cost of service study submitted for this proceeding which shows that the large majority of the costs large industrial customers impose on the distribution system (over 99%) are driven by their peak period demands. (ICC Staff Exhibit 17.0, pp. 38-39) If these customers are able to shift demand from peak to non-peak hours, their overall contribution to system costs will decline accordingly. (ICC Staff Exhibit 23.0, p. 2)

****270** Staff also contends that the reliability of the system may also improve. If incentives cause large industrial customers to shift their demands to non-peak periods there stands to occur significant benefits to system reliability. Peak period demands place maximum stress on ***399** a utility system, which can lead to interruptions or breakdowns in reliability. To the extent that demands are shifted to non-peak periods, the stresses on system reliability may be reduced. (ICC Staff Exhibit 23.0, p. 2)

Another benefit that Staff asserts is that shifting the loads of large industrial customers to non-peak hours would help offset the tendency of power costs to spiral upwards during peak hours. Power costs are generally understood to be highest during the peak period. These power costs are increasingly determined in the electricity market by the intersection of supply and demand. The tendency of power costs to spiral upwards during peak hours is caused by less supply. To the extent that peak period demands are shifted to non-peak hours, overall demand for power will decline during the peak period, thus increasing the amount of supply and helping offset the spiraling effect of power costs during peak hours.

Commissioners Ford and Lieberman also posed a set of questions regarding how other restructured states have priced distribution service for large customers. Staff states that it reviewed tariff pages for large customers in states that have restructured their electricity markets and found that some charges are based on demands during peak hours only, while others are based on 24 hour maximum demands as ComEd proposes to employ in this proceeding. (*Id.*). Staff argues that this variability indicates that there is no single, generally-accepted way to determine peak demands for setting demand charges.

Staff witness Lazare noted that state commissions appear to make individual decisions concerning the appropriate customer characteristics to measure and then set rates accordingly. (ICC Staff Exhibit 23.0, p. 8) The implication for the Commission, Staff asserts, is that the Commission should determine the objectives it wishes to achieve in the ratemaking process and then set rates that further those objectives. In Staff's estimation, the most reasonable and beneficial approach would be to reject the Company's proposal to move to a 24 hour maximum demand for all customers.

CUB-City

CUB and the City note that, at the hearing, there appeared to be almost no substantive disagreement in response to the questions posed by Commissioners Ford and Lieberman. The few disagreements that exist have been covered in response to III. H. 27. (Real Time Pricing Meters and Energy Smart Pricing Plan) above.

CCSAO

The Cook County State's Attorney's Office did not file any testimony in response to the Commissioners' questions on demand response. The CCSAO contends that this important issue should be the subject of a separate Commission proceeding.

Commission Analysis and Conclusion

****271** All parties are in agreement that demand response programs are a benefit to both customers and the system as a whole. This was evidenced through Commissioner questions and responses. Such a dense initiative, involving putting into operation programs on a statewide and regional basis, warrants an appropriate level of attention, thought and examination. In the procurement rider dockets the Commission ordered that demand response initiatives be researched in further rulemaking proceedings. Staff, as well as all interested parties, is encouraged to participate in such proceedings providing their recommendations. The significance of this issue warrants that it be given careful consideration in a separate proceeding. Such would not be the case within the confines of this docket.

XII. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) Commonwealth Edison Company is an Illinois corporation engaged in the transmission, distribution, and sale of electricity to ***400** the public in Illinois and is a public utility as defined in Section 3-105 of the Public Utilities Act;

(2) the Commission has jurisdiction over the parties and the subject matter herein;

(3) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; the Appendix attached hereto provides supporting calculations;

(4) the test year for the determination of the rates herein found to be just and reasonable should be the 12 months ending December 31, 2004; such test year is appropriate for purposes of this proceeding;

(5) for the test year ending December 31, 2004, and for the purposes of this proceeding, the Company's rate base is $5,521,350,000;

(6) a just and reasonable return which ComEd should be allowed to earn on its net original cost rate base is 8.01%; this rate of return incorporates a return on common equity of 10.045%, and on long-term debt of 6.48%;

(7) the rate of return set forth in Finding (6) results in base rate operating revenues of $1,585,997 and net annual operating income of $442,261,000 based on the test year approved herein;

(8) ComEd's rates which are presently in effect are insufficient to generate the operating income necessary to permit ComEd the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(9) the specific rates proposed by ComEd in its initial filing do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; ComEd's proposed rates should be permanently canceled and annulled consistent with the findings herein;

(10) ComEd should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $1,585,997,000 which represent an increase of $8,331,000 or 0.50%; such revenues will provide ComEd with an opportunity to earn the rate of return set forth in Finding (6) above; based on the record in this proceeding, this return is just and reasonable;

****272** (11) the determinations regarding cost of service, rate design, and terms and conditions of service contained in the prefatory portion of this Order are reasonable for purposes of this proceeding; the tariffs filed by ComEd should incorporate the rates, rate design, and terms and conditions set forth and referred to herein;

(12) new tariff sheets authorized to be filed by this Order should reflect an effective date not less than thirty (30) days after the date of filing, with the tariff sheets to be reviewed by the Rates Department of the Commission, and corrected, if necessary, within that time period;

(13) ComEd shall comply with the agreement described in this Order regarding when ComEd shall notify the

ICC of substantial changes to service company allocations in its Exelon General Services Agreement;

(14) ComEd shall file a copy of its FERC Form 60 with the ICC and provide a copy to the Manager of Accounting on the day it is filed with the FERC; and

(15) ComEd shall comply with the agreements described in this Order to file, as part of its ILCC Form 21, a report of BSC corporate governance charges and the additional schedules identified in this Order.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets presently in effect rendered by Commonwealth Edison Company are hereby permanently canceled and annulled, effective at such time as the new tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general rate increase, filed by Commonwealth Edison Company on August 31, 2005, are permanently canceled and annulled.

***401** IT IS FURTHER ORDERED that Commonwealth Edison Company is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (10), (11), and (12) of this Order, applicable to service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that any motions, petitions, objections, and other matters in this proceeding which remain outstanding are hereby denied.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission on this 26th day of July, 2006.

GLOSSARY OF ACRONYMS AND TERMS

[/kWh - Cents Per Kilowatt Hour Adjustment A & G - Administrative and General AAF - Accuracy Assurance Factor ABB - Asea Brown Boveri ABO - Accumulated Benefit Obligation ACSI - American Customer Satisfaction Index Proxy ADIT - Accumulated Deferred Income Taxes AFUDC - Adjustment for Funds Used During Construction AG - Attorney General of the State of Illinois AICPA - American Institute of Certified Public Accountants AIMR - Association for Investment Management and Research AIP - Annual Incentive Plan APS - Arizona Public Service Company APT - Arbitrage Pricing Theory ATO - Automatic Throw Over BAI - Brubaker & Associates, Inc. BES - Bundled Electric Service BES-H - Basic Electric Service-Hourly BES-L - Basic Electric Service-Lighting BES-NRA - Basic Electric Service-Nonresidential (Annual) BES-NRB - Basic Electric Service-Nonresidential (Blended) BES-R - Basic Electric Service-Residential BES-RR - Basic Electric Service-Railroad BG&E - Baltimore Gas & Electric Company BOMA - Building Owners and Managers Association, an intervening party BPPB - Budget Payment Plan Balances BUP - New Jersey Board of Public Utilities BWMQ - Brown, Williams, Moorhead & Quinn C & I - Commercial and Industrial CADOPS - ComEd's Operations Control Center CAIDI - Customer Average Interruption Duration Index CAMS - Control Area Management System CAPM - Capital Asset Pricing Model CCC - Citizens Utilities Board, Cook County State's Attorney's Office & City of Chicago. CCSAO - Cook County State's Attorney's Office CEC - Community Energy Cooperative CES - Coalition of Energy Suppliers, an intervening party ***402** CILCO - Central Illinois Light Company. CIMS - Customer Information Management System City - City of Chicago CLR - Capacity-Based Load Response & System Reliability Program CML - Capital Market Line CNE - Constellation New Energy, an intervening party CO - Capacity Obligation ComEd - Commonwealth Edison Company ComEd 2001 Rate Case - *Commonwealth Edison Company: Proposed General Increase in Delivery Service Tariffs Rates* , Illinois Commerce Commission, Docket No. 01-0423 Commission or ICC - Illinois Commerce Commission ConEd - Consolidated Edison Company Cons. - Consolidated (with respect to two or more dockets pending before the Illinois Commerce Commission). CPA - Certified Public Accountant CPCN - Certificate of Public Convenience and Necessity CPD - Chicago

Park District CPI - Consumer Price Index CPP - Competitive Procurement Process CPWG - Communications Protocol Working Group CS - Contract Service CSL - City of Chicago Street Lighting CSR - Customer Service Representative CTA - Chicago Transit Authority CTC - Customer Transition Charge CUB - Citizens Utility Board CWIP - Construction Work in Progress DASR - Direct Access Service Request DCF - Discounted Cash Flow DCS - Distributed Control System DFC - Distribution Facilities Charge DGAA - Designation of General Account Agency Direct - Direct Energy Services DLF - Distribution Load Factors DLR - Direct Load Control DST - Delivery Services Tariffs E2I - Electricity Innovation Institute ECOSS - Embedded Cost of Service Study ECR - Environmental Cost Recovery Adjustment EDI - Electronic Data Interchange EDSS - Energy Delivery Shared Services EED - Exelon Energy Delivery LLC EEI - Edison Electric Institute EGS - Electric Generation Supplier EIA - Energy Information Administration EIAS - Exelon Internal Audit Services EMCS - Energy Management Control System EPEC - Equal Percentage of Embedded Cost EPIS - Electric Plant in Service ***403** EPRI - Electric Power Research Institute ERISA - Employee Retirement Income Security Act ERT - Estimated Restoration Times ESC - Energy Service Companies ESIF - Energy Savings Income Fund ESPP - Energy Smart Pricing Plan ESSD - Electric Supplier Services Department Ex. - Exhibit Exelon BSC - Exelon Business Services Company FAQ - Frequently Asked Questions FAS - Financial Accounting Standard FCA - Franchise Cost Addition FERC - Federal Energy Regulatory Commission FFO - Funds From Operation FPC - Federal Power Commission GAA - General Account Agency GAAP - Generally Accepted Accounting Principles GCB - Government Consolidated Billing GDP - Gross Domestic Product GIS - Geographical Information System GRCF - Gross Revenue Conversion Factor GSA - General Services Agreement H & M - Harris and Marston HASC - Hourly Auction Supply Charge HVDS - High Voltage Delivery Service IAPA - The Illinois Administrative Procedure Act, 5 ILCS 100/1 *et seq.*. IAWA - Illinois Association of Wastewater Agencies, an intervening party. IDC - Integrated Distribution Company IDR - Interval Demand Recording IEDT - Illinois Electricity Distribution Tax IEEE - Institute of Electrical and Electronics Engineers IEPA - Illinois Environmental Protection Agency IFC - Instrument Funding Charge IIEC - Illinois Industrial Energy Consumers, an intervening party. IPL - Indianapolis Power & Light Company IPO - Initial Public Offering IRV - Interactive Voice Response ISO - Independent System Operators ISS - Interim Supply Service IT - Information Technology. ITC - Investment Tax Credits JBC - John Buck Company KPI - Key Performance Indicators KWH - Kilowatt-hour LDC - local distribution company LIHEAP - Low Income Home Energy Assistance Program LMP - Locational Marginal Prices LTIP - Long Term Incentive Plan MDS - Mobile Data System MGP - Manufactured Gas Plant ***404** MI - Market Index MIS - Management Information Systems MKD - Maximum Kilowatt Delivered ML - Meter-Related Facilities Lease MMF - Modified Massachusetts Formula Moody's - Moody's Investors Service MoPSC - Missouri Public Service Commission MOU - Memorandum of Understanding MSP - Meter Service Provider MSPS - Metering Service Provider Service MTP - Mandatory Transitory Periods MVM - Market Value Methodology MWG - Midwest Generation, an intervening party. MWH - Megawatt-hour NARUC - National Association of Regulatory Commissioners NCP - Non-Coincident Peak NERA - National Economic Research Associates NESC - National Electrical Safety Code NGPL - Natural Gas Pipeline Company of America NIGAS - Geological and Atmospheric Sciences and Agronomy at Iowa State University NIPSCO - Northern Indiana Public Service Company NIRCRC - Northeast Illinois Regional Commuter Railroad Corporation NOPR - Notice of Proposed Rulemaking NRC - Nuclear Regulatory Commission NYSEG - New York State Electric and Gas O&M - Operating and Maintenance OATT - Open Access Transmission Tariff OMS - Outage Management System OPEB - Postretirement Benefits Other Than Pensions P & A - Peak and Average PAPUC - Pennsylvania Public Utility Commission PECO - PECO Energy Company PES - Peoples Energy Services Corporation, an intervening party PG&E - Pacific Gas & Electric Company PJM - PJM Interconnection, L.L.C. PM - Primary Metering Adjustment POG - Parallel Operation of Retail Customer Generating Facilities POR - Purchase of