STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARNGES FOR ELECTRIC UTILITY SERVICE THORUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

APPENDIX TO INDIANA LABORERS DISTRICT COUNCIL'S POST-HEARING BRIEF

Intervenor Indiana Laborers District Council ("ILDC"), by counsel, hereby includes the following out-of-state Utility Commission decisions as an Appendix to its Post-Hearing Brief:

1. *In re Madison Gas and Elec. Co.*, Docket No. 3270-UR-115, WISCONSIN PUBLIC SERVICE COMMISSION, Final Decision (Dec. 14, 2007).

2. *W. Va.-Am. Water Co.*, Case No. 11-0740-W-GI, PUBLIC SERVICE COMMISSION OF WEST VIRGINIA, Commission Order (Oct. 13, 2011).

3. *Petition of the International Brotherhood of Electrical Workers Local No. 1245 to open an investigatory docket regarding the workforce staffing and planning of Sierra Pacific Power Company d/b/a NV Energy*, Docket No. 10-10013, PUBLIC UTILITIES COMMISSION OF NEVADA, Order (Feb. 25, 2011).

4. *Investigation into Cent. Vt. Pub. Serv. Corp.'s Staffing Levels*, Docket No. 7496, VERMONT PUBLIC SERVICE BOARD, Order (Aug. 20, 2009).

5. *Re N. Shore Gas Co.*, Docket No. 07-0241, ILLINOIS COMMERCE COMMISSION, Order (Feb. 5, 2008).

6. *In Re United Illuminating Co.*, Docket No. 05-06-04, CONNECTICUT DEPARTMENT OF PUBLIC UTILITY CONTROL, Order (Jan. 27, 2006).

7. *Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates*, Docket No. 3270-UR-115, WISCONSIN PUBLIC SERVICE COMMISSION, Final Decision (Dec. 18, 2008).

Respectfully submitted,

/s/ Neil E. Gath

Neil E. Gath, Attorney No. 11193-49
Brandon R. Magner, Attorney No. 35300-49
ngath@gathlaw.com
bmagner@gathlaw.com
GATH LAW OFFICE
P.O. Box 44042
Indianapolis, IN 46244
Telephone: (317) 489-5715
Facsimile: (317) 602-2180
Attorneys for the Intervenor
Indiana Laborers District Council

WISCONSIN

In re Madison Gas and Elec. Co., Docket No. 3270-UR-115, WISCONSIN PUBLIC SERVICE COMMISSION, Final Decision (Dec. 14, 2007).

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KeyCite Yellow Flag - Negative Treatment
Order Corrected by In re Madison Gas and Elec. Co., Wis.P.S.C., December 27, 2007

2007 WL 4632120 (Wis.P.S.C.)

Re Madison Gas and Electric Company

3270-UR-115

Wisconsin Public Service Commission

December 14, 2007

BY THE COMMISSION:

FINAL DECISION

This is the Final Decision regarding the application of Madison Gas and Electric Company (MGE) for authority to change electric and natural gas rates on January 1, 2008. *Final overall rate changes are authorized consisting of a $16,248,000 annual rate increase for electric utility operations, a 4.78 percent increase, and a $7,781,000 annual rate increase for natural gas utility operations, a 2.76 percent increase, for the test year ending December 31, 2008.*

Introduction

On May 7, 2007, MGE filed an application with the Commission requesting authority to increase its electric utility rates by $19,636,000, a 5.75 percent increase, and to increase its natural gas rates by $9,131,000, a 3.73 percent increase, to be effective January 1, 2008. MGE subsequently revised its electric request to $31,290,000, incorporating the following changes: (1) updated fuel and purchased power costs, in the amount of $8,500,000, based on the 12-month NYMEX strip prices on June 15, 2007; (2) the revenue requirement impact relating to Wisconsin Power and Light Company's (WP&L) proposed change in depreciation rates for Columbia Units 1 and 2, in the amount of $1,697,000; (3) the cost for Midwest Independent Transmission System Operator's (MISO) new Schedule 26 charge, in the amount of $1,235,000; (4) an updated estimate of property/boiler and machinery insurance, in the amount of $122,000; and (5) increased fuel and purchased power costs, in the amount of $100,000, resulting from WP&L changing the planned outage at Columbia Unit 2.

Shortly thereafter, MGE also reduced its request for additional electric revenues by $526,000 because of the following changes: (1) lowering the revenue requirement impact relating to WP&L's proposed change in Columbia depreciation rates by $316,000; (2) withdrawing MGE's request to increase fuel and purchased power costs because of WP&L's change in the planned outage at Columbia Unit 2; (3) withdrawing MGE's request to increase property/boiler and machinery insurance and requesting a $63,000 reduction to the forecasted cost of this insurance; and (4) requesting a $75,000 increase in medical and post-retirement medical costs.

Finally in its rebuttal testimony, MGE requested that the impact of the Commission's fuel surcharge order in docket 3270-FR-101, *Application of Madison Gas and Electric Company for Authority to Increase Electric Rates Established in Docket 3270-UR-114, Due to an Increase in 2007 Fuel Costs* (August 30, 2007), be incorporated in this proceeding. This request had the effect of reducing MGE's forecasted electric sales revenue in this proceeding in the amount of $3,248,000 and increasing MGE's revenue deficiency by a corresponding amount.

MGE's overall revised request results in a $34,012,000 increase, 9.99 percent, in revenues for electric utility operations.

On July 23, 2007, a prehearing conference was held to determine the issues that would be addressed in this docket and to establish a schedule for the hearing. The Commission held hearings for public comment on October 4, 2007, and a technical hearing to receive evidence from parties and Commission staff on October 5, 2007.

The Commission considered this matter at its open meeting on November 8, 2007.

The parties for purposes of review under Wis. Stat. §§ 227.47 and 227.53 are listed in Appendix A. Others who appeared are listed in the Commission's files.

Findings of Fact

1. It is reasonable to reflect $491,000 of estimated test year cost savings due to the MISO's anticipated June 1, 2008, implementation of its Ancillary Services Market (ASM).

2. It is reasonable in this proceeding to reflect a decrease to fuel costs of approximately $7,110,000 to update fuel costs for the impact of the New York Mercantile Exchange (NYMEX) natural gas futures strip as of October 15, 2007.

3. Fuel cost adjustments that decrease test year total fuel costs by $3,160,000 and increase monitored fuel costs by $625,000 relative to MGE's filed level are reasonable.

4. Test year total fuel costs of $129,849,839 are reasonable.

5. A test year fuel rules cost of monitored fuel of $119,094,430 is reasonable.

6. It is reasonable to monitor fuel costs using the following ranges: (1) plus or minus 8 percent monthly; (2) cumulative monthly ranges of plus or minus 8 percent for the first month, plus or minus 5 percent for the second month, and plus or minus 2 percent for the remaining months of the year; and (3) plus or minus 2 percent for the annual range.

7. MGE shall calculate the return on carrying costs on Elm Road Generating Station (ERGS) construction expenditures at the short-term debt rate approved in this docket. MGE shall also calculate the return on management fees, community impact mitigation costs, and 2007 operation and maintenance (O&M) expenses associated with ERGS at the short-term debt rate approved in this docket.

8. It is reasonable to authorize MGE escrow accounting treatment for billing charges from its affiliate MGE Power Elm Road, LLC (MGEPER) relating to MGE's share of ERGS Q&M expenses that began in 2007.

9. It is reasonable for MGE to continue accounting for billing charges from MGEPER for its share of carrying costs on ERGS construction expenditures, management fees, and community impact mitigation costs on an escrow basis.

10. The level of billing charges from MGEPER relating to ERGS costs recoverable in rates for the test year is $12,103,445. This consists of carrying costs on construction expenditures in the amount of $9,571,000, community impact mitigation costs in the amount of $237,405, management fees in the amount of $184,841, and 2007 and 2008 O&M expenses in the amount of $2,110,199.

11. It is reasonable to reclassify balancing authority labor costs from a utility O&M expense to a balance sheet account for ratemaking purposes.

12. MGE shall report to the Commission identifying the extent of the challenges regarding workforce planning, the specific actions that MGE is taking to address the issue, and the progress MGE is making toward meeting those goals.

13. Since the Commission has not yet issued an order in docket 6680-DU-104, it is reasonable to defer MGE's revenue requirement impact relating to WP&L's proposed change in depreciation rates applicable to Columbia Units 1 and 2 to the 2009 limited reopening of MGE's rates.

14. It is reasonable to include the cost resulting from MGE updating its estimate of property/ boiler and machinery insurance in MGE's electric and natural gas revenue requirement.

15. It is reasonable to include the cost resulting from MGE updating its estimate of medical/hospital insurance and post-retirement medical costs in MGE's electric and natural gas revenue requirement.

16. It is reasonable to include the cost associated with a new MISO Schedule 26 charge (Network Upgrade Charge from Transmission Expansion Plan) in MGE's electric revenue requirement.

17. It is reasonable to incorporate the September update of American Transmission Company's (ATC) network service charge in MGE's electric revenue requirement.

18. It is reasonable to include the impacts of the *Final Decision* in docket 3270-FR-101 in MGE's electric revenue requirement.

19. A limited reopening of MGE's rates for 2009 is reasonable.

20. A reasonable level of expensed conservation costs recoverable in rates for the test year is $7,061,555 for electric operations and $5,388,551 for natural gas operations. The level for electric operations consists of the conservation budget in the amount of $6,396,555 plus an escrow adjustment of $665,000, which represents the amortization of the projected overspent balance at December 31, 2007, over a two-year period. The level for natural gas operations consists of the conservation budget in the amount of $4,824,551 plus an escrow adjustment of $564,000, which represents the amortization of the projected overspent balance at December 31, 2007, over a two-year period.

21. It is reasonable to continue accounting for allowable electric and gas conservation expenditures on an escrow basis.

22. It is reasonable to include all uncontested Commission staff adjustments to MGE's filed operating income statements and average net investment rate bases in the test year.

23. At present rates, the estimated electric utility net operating income for the test year is $28,487,000. The estimated net operating income applicable to natural gas utility operations for the test year at present rates is $6,813,000.

24. The estimated average net investment rate base applicable to electric utility operations is $421,081,000. The average net investment rate base applicable to natural gas utility operations is $126,241,000.

25. The pro forma rate of return on average net investment rate base at present rates for electric utility operations for the test year is 6.77 percent. For natural gas utility operations, the pro forma rate of return at present rates for the test year is 5.40 percent.

26. It is reasonable for MGE to maintain a common equity ratio for ratemaking purposes of approximately 57 percent. A reasonable ratemaking capital structure for the test year is 57.36 percent common equity, 36.89 percent long-term debt, and 5.75 percent short-term debt.

27. A reasonable estimate of the cost of long-term debt, including the cost of the new long-term issues, for the test year is 6.18 percent. This rate is based in part on a 2007 long-term debt issuance at a cost rate of 6.247 percent (actual), and a 2008 long-term debt issuance at a cost rate of 5.95 percent (projected).

28. A reasonable estimate of the cost of short-term debt for the test year is 4.83 percent.

29. It is reasonable to set the fair return on equity based on proper estimates of the cost of equity and regulatory financial policy. A reasonable fair return on equity for MGE's test year is 10.80 percent.

30. A reasonable weighted average composite cost of capital is 8.75 percent.

31. It is reasonable for MGE to earn a current return on 50 percent of test year construction work in progress (CWIP), and for the remaining CWIP to accrue allowance for funds used during construction (AFUDC) at the adjusted weighted cost of capital.

32. A reasonable test year rate of return on average net investment rate base for electric utility operations is 9.08 percent. For natural gas utility operations a reasonable test year rate of return on average net investment rate base is 9.09 percent.

33. To produce a return of 9.08 percent on average net investment rate base in the test year, MGE's operating revenue requirement for electric utility operations is $365,834,000. The revenue requirement for natural gas utility operations, to produce a return of 9.09 percent on average net investment rate base in MGE's test year, is $289,988,000.

34. Present rates for electric utility operations will produce operating revenues of $349,586,000, which results in an annual revenue deficiency of $16,248,000. Present electric rates of MGE are unreasonable because the revenues produced by these rates are inadequate.

35. Present rates for natural gas utility operations will produce operating revenues of $282,207,000, which results in an annual revenue deficiency of $7,781,000. Present natural gas rates of MGE are unreasonable because the revenues produced by these rates are inadequate.

36. To provide operating revenues to cover total cost of service for the test year, an increase in revenue applicable to electric utility operations in the amount of $16,248,000 is required. For natural gas utility operations, an increase in the amount of $7,781,000 is required. These increases in electric and natural gas utility rates are reasonable.

37. It is reasonable to modify the Gas Cost Recovery Mechanism (GCRM) as discussed in the Opinion section of this Final Decision. It is reasonable for the modifications to take effect November 1, 2008.

38. It is reasonable to require that MGE receive Commission staff's acceptance of any changes to MGE's 2008 customer service conservation activities before MGE implements them.

39. It is appropriate for MGE to work with Commission staff to develop measures of success for its 2008 customer services conservation activities, using 2007 measures of success as a starting point.

40. It is reasonable to rely on the results of one or more cost-of-service studies (COSS) along with other factors, such as bill impacts, when allocating revenue responsibility.

41. It is appropriate to require that MGE work with Commission staff to collect more information about the production cost allocator to assist the Commission in its decision-making process. It is reasonable to require that MGE present this information in its next rate case application.

42. It is reasonable to approve rates for electric service and for natural gas service for the test year to achieve customer class changes in revenue, as shown in Appendices B and C.

43. The standard electric buyback rates shown in Appendix B are reasonable.

44. The proposed Pg-4 Experimental Photovoltaic Parallel Generation service schedule is reasonable.

45. A green pricing premium of 1[per kWh is reasonable.

46. The changes proposed by MGE to the Business Renewable Energy Program service schedule are reasonable.

Conclusions of Law

1. MGE is an electric and natural gas public utility as defined in Wis. Stat. § 196.01(5)(a).

2. The Commission has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, 196.395, and 196.40 and Wis. Admin. Code chs. PSC 113, 116, and 134 to enter an order authorizing MGE to place in effect the rates and rules for electric and natural gas utility service set forth in Appendices B and C, and the fuel cost treatment set forth in Appendix D, subject to the conditions specified in this Final Decision. Such rates and rules for electric and natural gas utility service in Appendices B, C, and D are reasonable and appropriate as a matter of law.

Opinion

MGE and Its Business

MGE is engaged in the production, transmission, distribution, and sale of electric energy to approximately 137,000 retail customers in Madison and the surrounding area in Dane County, and in the purchase, transportation, distribution, and sale of natural gas to approximately 138,000 customers in Madison and the surrounding area in Dane County, as well as in Columbia, Crawford, Iowa, Juneau, Monroe, and Vernon Counties. MGE is an operating subsidiary of MGE Energy, a holding company based in Madison, Wisconsin.

Income Statement

MGE, intervenors, and Commission staff presented testimony and exhibits at the hearing concerning estimates of MGE's 2008 electric and natural gas utility operations. Significant issues pertaining to the income statement are addressed separately below.

Fuel Costs

Commission staff adjusted MGE's fuel costs to reflect the cost savings associated with MISO's anticipated implementation of its ASM on June 1, 2008. Commission staff estimated the test year cost savings by multiplying MISO's estimate of system-wide annual net benefits by MGE's load ratio share to arrive at MGE's estimated savings on an annual basis, and then multiplying by 7/12 to arrive at MGE's estimated test year fuel cost savings due to MISO implementing the ASM.

In rebuttal testimony, MGE stated that the Commission should not accept this adjustment, or at a minimum reduce the adjustment to reflect a September 1, 2008, implementation date, due to MISO's history of delays in implementing markets and the tight timeline of events that must occur in order for MISO to implement the ASM on June 1, 2008. Commission staff responded stating that as MISO had not indicated any intent to delay the ASM implementation date past June 1, 2008, that it would not propose any change to its adjustment reflecting MGE's test year estimated cost savings due to the implementation of the ASM. Commission staff did, however, propose that if MISO were to announce a delay in implementation, MGE be allowed to file an exhibit documenting any such delay, and reflecting the impact on the estimated ASM cost savings due to any such delay.

As no such exhibit was received, and as MISO has not announced its intent to delay implementation of its ASM, or missed any milestones required for implementation, the Commission accepts Commission staff's proposed adjustment to reflect the estimated cost savings associated with MISO's implementation of its ASM. It is reasonable to reflect $491,000 of estimated fuel cost savings due to MISO's implementation of its ASM, in MGE's test year revenue requirement.

Commission staff based its estimate of natural gas-fired and purchased power costs on more current NYMEX natural gas futures prices, which increased the electric revenue requirement by approximately $8.5 million. On October 31, 2007, MGE filed a delayed exhibit reflecting a decrease of $7,110,000 million to fuel costs resulting from updating the NYMEX natural gas futures strip from the June 15, 2007, futures strip used by Commission staff, to the October 15, 2007, futures strip, which was the most recent available mid-month NYMEX natural gas futures strip. The Commission considers this fuel cost decrease to be reasonable. The Commission also considers Commission staff's fuel cost adjustments, which decrease test year total fuel costs by $3,160,000 and increase monitored fuel costs by $625,000 relative to MGE's filed level, to be reasonable.

The Commission finds that a reasonable test year level of fuel costs is $129,849,839. A reasonable test year level of monitored fuel costs is $119,094,430, which reflects the cost of generation and purchased energy, less the revenues from opportunity sales of energy and capacity. This test year fuel cost divided by the test year estimate of native energy requirements of 3,483,170 MWh results in an average net fuel cost per kWh of $0.03419.

Any cost for purchased capacity that is required to meet reserve requirements is excluded from monitored fuel rules costs and may only be adjusted in a rate case. Firm transmission associated with excluded capacity purchases, fuel and ash handling, and sulfur dioxide (SO2) allowance costs are excluded as well. Appendix D shows the monthly fuel costs to be used for monitoring purposes.

Under Wis. Admin. Code § PSC 116.04, the Commission establishes monthly and annual variance ranges for monitoring fuel forecasts. The Commission finds it is reasonable to continue to monitor MGE's fuel costs using the following ranges: (1) plus or minus 8 percent monthly; (2) cumulative monthly ranges of plus or minus 8 percent for the first month, plus or minus 5 percent for the second month, and plus or minus 2 percent for the remaining months of the year; and (3) plus or minus 2 percent for the annual range.

The method of applying these ranges, established in prior Commission decisions for MGE, shall continue to be used and applied, using the data in Appendix D for monitoring fuel costs.

Return on Carrying Costs on ERGS Construction Expenditures

In docket 3270-UR-114, MGE's last rate case proceeding, the Commission found MGE's proposal to collect 2005 and 2006 carrying costs on ERGS construction expenditures over two years to be reasonable. The Commission ordered MGE to calculate the return on these costs, as well as on management fees and community impact mitigation costs associated with ERGS, on the average monthly balance at the short-term debt rate approved in that docket.

In this proceeding, MGE proposed to collect 2007 and the true-up of 2005 and 2006 carrying costs on ERGS construction expenditures over two years. In addition, MGE proposed to collect the 2008 carrying costs on ERGS construction expenditures over four years in order to lower the rate impact to its customers. Consistent with the order in docket 3270-UR-114, Commission staff calculated the return on carrying costs on ERGS construction expenditures, as well as on management fees, community impact mitigation costs, and 2007 O&M expenses associated with ERGS, at Commission staff's estimated short-term debt rate. In rebuttal testimony, MGE testified that because its recovery of the 2008 cost will be spread over four years, it should earn a return on these costs at the economic cost of capital, which is a long-term rate as opposed to the short-term debt rate.

The Commission continues to find it reasonable that MGE calculate the return on carrying costs on ERGS construction expenditures at the short-term debt rate approved in this docket. The Commission also finds it reasonable that MGE calculate the return on management fees, community impact mitigation costs, and 2007 O&M expenses associated with ERGS at the short-term debt rate approved in this docket.

Escrow Accounting for ERGS O&M Expenses

In docket 3270-UR-114, the Commission authorized MGE to account for billing charges from its affiliate MGEPER for its share of carrying costs on ERGS construction expenditures, management fees, and community impact mitigation costs on an escrow basis. In this proceeding, MGE has requested that 2007 and 2008 ERGS O&M expenses also be escrowed. The Commission agrees and authorizes MGE to escrow billing charges from its affiliate MGEPER for its share of the ERGS O&M expenses that began in 2007. It is also reasonable for MGE to continue accounting for billing charges from MGEPER for its share of carrying costs on ERGS construction expenditures, management fees, and community impact mitigation costs on an escrow basis.

The level of billing charges from MGEPER relating to ERGS costs recoverable in rates for the test year is $12,103,445. This consists of carrying costs on construction expenditures in the amount of $9,571,000, community impact mitigation costs in the amount of $237,405, management fees in the amount of $184,841, and 2007 and 2008 O&M expenses in the amount of $2,110,199.

Ratemaking Treatment for Schedule 24 Balancing Authority Labor Costs

MGE's initial filing included $541,000 of Schedule 24 balancing authority labor costs in FERC Account 561, Load Dispatching, and $427,600 of balancing authority labor reimbursements that MGE subsequently updated to $509,700. The labor reimbursements included in the test year relate to labor costs that were included in MGE's base rates in prior years. Commission staff decreased transmission expenses by $541,000 to reclassify the balancing authority labor costs, which MGE subsequently bills MISO, from a utility O&M expense to a balance sheet account for ratemaking purposes.

MGE indicated that as a condition for reimbursement, MISO requires that Schedule 24 charges be recorded as a balancing authority cost in FERC Account 561. MGE contends that transferring these costs to a balance sheet account will jeopardize its ability to recover the costs from MISO.

Commission staff proposed that MGE reclassify the balancing authority costs to a balance sheet account only for ratemaking purposes, not on MGE's books. This adjustment is similar to others the Commission makes, such as adjustments to dues. While utilities generally include dues in an O&M expense account, the Commission considers a portion of these dues as a below-the-line cost for ratemaking purposes. The Commission therefore finds it appropriate to reclassify balancing authority labor costs from a utility O&M expense to a balance sheet account for ratemaking purposes.

Comprehensive Workforce Planning

IBEW Local 2304 requested that the Commission: (1) require MGE to prepare and submit for Commission review a ten-year written plan relating to comprehensive workforce planning; (2) approve whatever revenue may be necessary for MGE to engage in the recruitment retention, hiring, and training that are necessary components of its comprehensive workforce plan; and (3) require that MGE's efforts are verifiable with objective results and are subject to review in this test year and again in a subsequent year.

MGE testified that its current planning horizon is from five to eight years and that planning for projected turnover and staffing levels beyond eight years is too uncertain. MGE noted that the Commission has partnered with the Department of Workforce Development in bringing the utilities, labor unions, and other parties together to discuss workforce planning issues and that these broader, more generic forums, involving a whole range of stakeholders, are the appropriate means of addressing Commission concerns regarding comprehensive workforce planning.

The Commission agrees with IBEW Local 2304 that this issue must be addressed, which is why it is presently focusing on the problem in conjunction with the Wisconsin Department of Workforce Development. This work group should complete its deliberations and issue recommendations shortly. The Commission finds it reasonable to require that MGE report to Commission staff in 2008, identifying the workface challenges it is facing, the actions it is and will be taking to address these challenges, and the progress MGE is making toward meeting its goals. In its report, MGE shall also explain how it is implementing any recommendations from the work group. If MGE is not implementing one of these recommendations, it shall explain why, and what it is doing in the alternative. Commission staff may ask MGE to provide portions of this report in writing as needed.

WP&L's Proposed Change in Depreciation Rates for Columbia Units 1 And 2

On May 23, 2007, WP&L filed an application with the Commission requesting a change in depreciation rates in docket 6680-DU-104, *Application of Wisconsin Power and Light Company for Change in Book Depreciation Rates*. WP&L's proposal includes an increase in depreciation rates applicable to Columbia Units 1 and 2, of which MGE is a joint owner.

In supplemental direct testimony, MGE indicated that Commission approval of the proposed change in depreciation rates for WP&L's Columbia plant would increase depreciation expense by $1,776,000, partially offset by a decrease in rate base resulting in a net increase of $1,697,000 in MGE's electric revenue requirement. MGE requested that this amount be included in its revenue requirement and proposed that if the Commission granted MGE's request, the increase should be subject to refund for any portion of the test year prior to the Commission's final approval of WP&L's proposed change in depreciation rates in docket 6680-DU-104. In additional testimony, MGE reduced its request to $1,381,000.

Commission staff modified the company's request by proposing that if an order is issued in docket 6680-DU-104 prior to the Commission's decision in this proceeding, the results of that order relating to WP&L's Columbia plants should be incorporated in this docket. Because the Commission has not yet issued a depreciation order in WP&L's proceeding, which means changes in depreciation rates and their rate impact remain uncertain, the Commission finds it reasonable to defer MGE's revenue requirement impact relating to the proposed change in depreciation rates applicable to Columbia Units 1 and 2 to the 2009 limited reopener.

Property/Boiler and Machinery Insurance

MGE's filed estimate for property/boiler and machinery insurance (excluding the West Campus Cogeneration Facility and the Top of Iowa 3 Wind Generating Facility) was $847,000, reflecting a 50 percent increase for its September 1, 2007 through August 31, 2008, premium and a 15 percent increase for its September 1, 2008 through August 31, 2009, premium. Due to the lack of support from MGE's insurance carrier, Commission staff reduced the September 1, 2007 through August 31, 2008, premium increase to 15 percent. Commission staff's proposal reduced MGE's filed estimate by $185,000.

In supplemental direct testimony, MGE indicated that it had received a more recent quote from its insurance carrier that increased the test year cost by approximately $122,000 above MGE's filed estimate. MGE then proposed to control this cost increase by doubling the deductible on its policy, thereby saving $185,000. MGE subsequently withdrew its request for the additional $122,000 and also agreed to an adjustment that would reduce its filed amount by $63,000. Commission staff agreed, also recommending that MGE's filed estimate be reduced by only $63,000 (increasing Commission staff's proposed electric revenue requirement by $117,000 and its proposed natural gas revenue requirement by $5,000). The Commission concurs, finding that MGE's current estimate in the amount of $784,000 ($847,000 - $63,000) is reasonable for the 2008 test year.

Medical/Hospital Insurance and Post-Retirement Medical Costs (FASB 106)

Commission staff proposed a decrease in MGE's forecasted post-retirement medical costs of $151,000, reflecting Commission staff's discount rate assumption and O&M percentage, and proposed an increase in MGE's filed level for medical/hospital insurance costs of $88,000, reflecting Commission staff's O&M percentage. These adjustments resulted in a net decrease of $63,000 for these two items.

MGE introduced supplemental testimony that it had reached an agreement in principle with its carriers on health insurance rates, which also allowed it to calculate post-retirement medical costs more accurately. Based on these updated estimates, MGE requested that an additional $75,420 be added to its revenue requirement. Commission staff agreed with these calculations.

The Commission concurs. As a result, Commission staff's proposed electric revenue requirement is increased by $88,000 and its natural gas revenue requirement is increased by $50,000 for a total increase of $138,000. MGE's updated estimates for medical/hospital insurance and post-retirement medical costs are reasonable for the 2008 test year.

MISO Schedule 26 Charge

MGE requested that $1,235,000 be added to its initially-filed electric revenue requirement for a new MISO Schedule 26 charge, known as MISO's Network Upgrade Charge from Transmission Expansion Plan. This charge pertains to MISO's sharing of costs for new transmission facilities. Including this cost in the electric revenue requirement is reasonable.

September Update for ATC Network Service Fee

MGE's filing included an estimate of $22,050,000 for the ATC network service fee. MGE's estimate was based on information provided by ATC in January 2007. At the hearing, MGE indicated that ATC had recently provided a late-September update, showing that the network service fee will be $22,406,000. Incorporating ATC's current estimate of the ATC network service charge in the test year, which increases the electric revenue requirement by $356,000, is reasonable.

Test Year Impacts Resulting from the Final Decision in Docket 3270-FR-101

In this proceeding, MGE and Commission staff both estimated test year sales based on MGE's prior rates approved in the *Final Decision* in docket 3270-UR-114, plus the surcharge the Commission authorized in the *Interim Order* in docket 3270-FR-101, *Application of Madison Gas and Electric Company for Authority to Increase Electric Rates Established in Docket 3270-UR-114, Due to an Increase in 2007 Fuel Costs* (April 26, 2007).

On August 30, 2007, the Commission issued its *Final Decision* in docket 3270-FR-101. In rebuttal testimony, MGE requested that the impacts of that *Final Decision* be incorporated in this proceeding. Based on Commission staff's estimate of test year sales, which MGE did not contest, the *Final Decision* in docket 3270-FR-101 lowered electric revenues at present rates by $3,268,000. This decrease in present revenues also lowers Commission staff's estimate of electric uncollectible accounts expense by $14,000. The Commission finds it appropriate to include the impacts of the *Final Decision* in docket 3270-FR-101 in this proceeding, which results in a $3,254,000 net increase in MGE's electric revenue deficiency.

Rate Case Reopening for Test Year 2009

MGE indicated it would consider foregoing a 2009 rate case if certain issues could be addressed in a limited rate reopening for test year 2009. MGE identified the following issues for such a reopening related to electric operations: (1) monitored fuel rules costs; (2) escrow adjustment for 2005 Wisconsin Act 141 (Act 141) costs; (3) ERGS lease payments and other O&M expenses resulting from ERGS Unit 1 becoming operational in 2009; (4) updated ATC network service fees; (5) update for changes to pension, medical, and supplemental retirement costs; and (6) adjustment to recover environmental cost increases at Columbia. The items for a reopening that MGE identified relating to natural gas operations were: (1) update to cover the increase in Act 141 funding and (2) update for changes to pension, medical, and supplemental retirement costs.

In rebuttal testimony, MGE withdrew its request to include Act 141 costs (electric and natural gas), since they are being escrowed, and withdrew its request to include environmental cost increases at Columbia in light of the Commission's recent approval of deferral accounting for these costs. However, MGE requested that it be allowed to accrue carrying costs at the adjusted weighted cost of capital on 100 percent of environmental upgrades at the Columbia Energy Center upon the Commission's approval of these upgrades, until the effective date of the *Final Decision* in MGE's next full rate case. MGE also requested that the 2008 and 2009 balancing authority labor reimbursements, totaling $682,900, be amortized over two years if the Commission approves a 2009 limited rate reopening. At the hearing, MGE requested that its share of 2009 incremental O&M expenses relating to the reduction of mercury emissions at the Columbia Generating Station be added to the issues to be considered in a 2009 rate reopening.

Intervenor Robert Owen suggested that the Commission include certain rate design reforms in a 2009 rate reopening if it approves rate design changes in this proceeding, but finds it necessary to delay implementation for some short-term reason such as to collect more data.

The Commission agrees that a 2009 limited rate reopening is reasonable, for the following items: (1) monitored fuel rules costs; (2) ERGS lease payments and other O&M expenses resulting from ERGS Unit 1 becoming operational in 2009; (3) updated ATC network service fees; (4) the accrual of carrying costs at the adjusted weighted cost of capital, for future environmental upgrades at the Columbia Energy Center upon the Commission's approval of the upgrades, until the effective date of the *Final Decision* in MGE's next full rate case; and (5) a review of MGE's rate design to provide price signals for reducing greenhouse gas emissions.

Conservation Budget and Escrow Adjustment

A reasonable level of expensed conservation costs recoverable in rates for the test year is $7,061,555 for electric operations and $5,388,551 for natural gas operations. The level for electric operations consists of the conservation budget in the amount of $6,396,555 plus an escrow adjustment of $665,000, which represents the amortization of the projected overspent balance at December 31, 2007, over a two-year period. The level for natural gas operations consists of the conservation budget of $4,824,551 plus an escrow adjustment of $564,000, which represents the amortization of the projected overspent balance at December 31, 2007, over a two-year period. Included in the electric conservation budget is $3,526,000 related to Act 141 energy efficiency and renewable resource funding requirements. The natural gas conservation budget includes $2,440,000 related to Act 141 requirements. It is reasonable to require MGE to continue accounting for allowable conservation expenditures on an escrow basis.

Summary of Operating Income Statements at Present Rates

In addition to the Commission's findings regarding specific items discussed in this opinion, the Commission agrees that all other uncontested Commission staff adjustments to MGE's filed operating income statements are reasonable and just. Accordingly, the estimated electric and natural gas utility operating income statements at present rates for the test year, which are reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Electric (000's)	Natural Gas (000's)
Operating Revenues		
Sales of Electricity	$340,127	$-
Sales for Resale	7,981	-
Sales of Gas	-	281,529
Other Operating Revenues	1,478	678

Total Operating Revenues	$349,586	$282,207
	....	....
Operating Expenses		
Steam Power Generation Expenses	$118,876	$-
Other Power Generation Expenses	5,099	-
Other Power Supply Expenses	64,714	-
Manufactured Gas Production Expenses	-	391
Purchased Gas Expenses	-	224,236
Transmission Expenses	25,829	-
Distribution Expenses	12,412	7,561
Customer Accounts Expenses	6,713	5,634
Customer Service Expenses	8,255	6,578
Administrative & General Expenses	29,416	16,205
	....	....
Total Operation & Maintenance Expenses	$271,314	$260,605
Depreciation and Amortization Expense	28,246	9,710
Taxes Other Than Income Taxes	13,097	3,527
Deferred Income Taxes	5,150	(532)
State Income Taxes	957	377
Federal Income Taxes	2,523	1,870
Investment Tax Credit	(188)	(163)
	....	....
Total Operating Expenses	$321,099	$275,394
	....	....
Net Operating Income	$28,487	$6,813
	=	=

Summary of Average Net Investment Rate Bases

Commission staff proposed a number of adjustments to MGE's filed electric and natural gas utility average net investment rate bases. No party opposed these adjustments and the Commission finds them reasonable. Accordingly, the estimated electric and natural gas average net investment rate bases for the test year, which are reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Electric (000's))	Natural Gas (000's)
Utility Plant in Service	$775,089	$282,246
Less: Reserve for Depreciation	303,945	160,670
Net Utility Plant	$471,144	$121,576
Add: Fuel Inventory	5,403	-
Stored Gas	-	20,857
Materials and Supplies	11,486	1,865
Less: Accumulated Deferred Income Taxes	65,841	15,795
Customer Advances for Construction	1,111	2,262
Average Net Investment Rate Base	$421,081	$126,241
	=	=

Pro Forma Rate of Return

At present rates, the net operating income for the test year ending December 31, 2008, would result in a rate of return on the average net investment rate base of 6.77 percent for electric utility operations and 5.40 percent for natural gas utility operations. As described below, this rate of return is unreasonably low.

Financial Issues

Capital Structure

MGE's application is based on a capital structure consisting of 57 percent common equity. Wisconsin Industrial Energy Group (WIEG) suggested that such a common equity ratio is abnormally high and recommended that the Commission consider that fact when establishing the return on equity.

The common equity ratio is a key determinant of a utility's financial position. The utility's proposed common equity ratio is in keeping with regulatory financial policies established by this Commission. This Commission has favored financially strong utilities relative to standard industry policy, and no convincing evidence was offered in this proceeding to change that view.

After ratemaking adjustments made to reflect the Commission's decisions in this proceeding, the resulting common equity ratio is 57.36 percent. Such a common equity ratio is reasonable. It is also reasonable that the remainder of the capital structure consist of 36.89 percent long-term debt and 5.75 percent short-term debt.

Cost of Long-Term Debt

The cost of long-term debt is a weighted average of the embedded cost of debt issued in prior years and the cost of new issues. In this proceeding, the utility proposed to issue new long-term debt in late 2007 and again in late 2008. It subsequently issued the 2007 securities before the record closed. The effective interest rate for that issuance is 6.247 percent, which the Commission incorporates in its calculation of the cost of long-term debt.

The 2008 issuance will occur in the future, and therefore the interest rate on that issuance must be estimated. The utility proposed that the rate for that issue be set at 6.25 percent. Commission staff suggested that, based on long-established finance principles, current interest rates are likely to be the most accurate estimates of future interest rates.

The Federal Reserve Board recently reduced its Fed funds interest rate target and both long- and short-term interest rates have declined in response. The latest information about long-term interest rates entered into the record is that they now are below 6 percent. It is reasonable to set the estimated cost of the 2008 long-term issue at 5.95 percent, in keeping with current financial market rates. Combining the rates for the new 2007 and 2008 issues with the embedded cost of previously issued debt produces an effective long-term debt cost of 6.18 percent, which is reasonable.

Cost of Short-Term Debt

The utility proposed a short-term debt cost of 5.25 percent. In keeping with its view on interest rate forecast accuracy, Commission staff suggested that the Commission use the most recently observed rates as the forecast for the test year.

As noted above, as a result of the recent Federal Reserve Board action, interest rates have declined. Based on current short-term debt rates, it appears that the utility can raise capital on a short-term basis at 4.83 percent, which is a reasonable rate for the test year.

Fair Return on Equity

The record in this proceeding contains a substantial discussion of fundamental regulatory finance concepts. As Commission staff explained, the cost of equity, which is estimated from market data, is separate and distinct from the fair return on equity, which the Commission must establish when setting rates. Under Commission staff's approach, the cost of equity is just one of seven key factors that determine the return on equity. The other factors are the need to: provide economic incentives; maintain rate stability; price utility services in keeping with those observed in other industries; consider consumer interests; consider existing investors; and recognize managerial efficiency. The utility and WIEG agreed with Commission staff's conceptual approach.

The only cost of equity model estimates presented on the record were those prepared by Commission staff. It relied on the discounted cash flow model, the capital asset pricing model, and the risk premium model to estimate a cost of equity range of 8.1 percent to 9.1 percent, with a median estimate of 8.4 percent. WIEG suggested that such estimates were reasonable in that the S&P Utility Index has produced returns near that level for the past five years. The utility presented no formal cost of equity analysis.

The utility focused its analysis instead on the return on equity, suggesting that an 11.00 percent return was the minimum level that would enable it to maintain its current financial integrity. WIEG argued that the return on equity could be reduced to 10.00

percent or lower without causing undue harm to the utility's investors. Commission staff suggested that the fair return on equity lies in the range of 10.50 to 10.75 percent.

The Commission finds the proposed conceptual framework proposed by the Commission staff to be reasonable. The cost of equity, which is the minimum acceptable return, is a starting point. It would drive utility market values to book value, which eliminates the economic incentive for utilities to expand their systems. Under normal economic conditions, the fair return on equity lies above that minimum rate.

Determining the fair return on equity involves matters of regulatory policy, such as the fact that Commission's present policy is to set biennial rates for a utility, which may slightly increase the rate of return, rather than conduct annual rate cases. The U.S. Supreme Court has made it clear that the establishment of a fair return on equity is not a mathematical exercise. *Federal Power Com'n v. Hope Natural Gas Co*., 320 U.S. 591, 602 (1944). No equation or model could provide the answer to such a complex public policy issue. The ultimate determination involves a balancing of consumer and investor interests. The Commission finds that a return on equity of 10.80 percent will reasonably achieve that balance, protecting both the utility's investors and the public interest.

Considering the capital structure determination, the cost rate estimates for short- and long-term debt, and the fair return on equity, the following cost of capital figures shall be used for ratemaking in this proceeding:

	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$336,804	57.36%	10.80%	6.19%
Long-Term Debt	216,577	36.89%	6.18%	2.28%
Short-Term Debt	33,767	5.75%	4.83%	0.28%
Total Utility Capital	$587,148	100.00%		8.75%
	=	=		=

The weighted cost rate of 8.75 percent is reasonable for the test year. It generates an economic cost of capital of 12.90 percent, and a pre-tax interest coverage of 5.04 times.

Rate of Return on Rate Base

The 8.75 percent composite cost of capital must be translated into a rate of return, which can then be applied to the average net investment rate base and used to compute the overall return requirement in dollars. The estimate of MGE's average net investment rate bases plus CWIP for the test year is 99.77 percent of capital applicable primarily to utility operations plus deferred investment tax credit. This estimate reflects all appropriate Commission adjustments, and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to the average net investment rate base.

To allow a test year current return on the average CWIP balance, an adjustment must be added to the return on net investment rate base. Given MGE's financing and cash flow requirements in the test year and the forecasted amount of construction activity, it is reasonable to allow a current return on 50 percent of CWIP for the test year. In addition, an adjustment is needed to reflect the tax savings on MGE's Industrial Development Revenue Bonds entirely in the electric revenue requirement. Lastly, an adjustment is needed to include a return on the unamortized balances relating to carrying costs on ERGS construction expenditures, ERGS community impact mitigation costs and management fees, and ERGS O&M expenses at MGE's short-term debt rate.

Accordingly, the rates of return on average electric and natural gas utility net investment rate bases, which are reasonable for the purpose of determining just and reasonable rates in this proceeding, are as follows:

	Electric	Natural Gas
Cost of Capital	8.75%	8.75%
Average Percent of Utility Net Investment Rate Base Plus		
CWIP to Capital Applicable Primarily to Utility		
Operations Plus Deferred Investment Tax Credit	99.77%	99.77%
Percent Return Requirement Applicable to Average Net		
Investment Rate Base	8.77%	8.77%
Adjustment to Return Requirement to Provide Current		
Return on 50 percent of CWIP	0.28%	0.20%
Adjustment to Reflect Tax Savings on Industrial		
Development Revenue Bonds	(0.04%)	0.12%
Carrying Costs on ERGS Construction Expenditures		
(000's)	$5,528	-
ERGS Community Impact Mitigation Costs/Management		
Fees (000's)	(15)	-
ERGS 2007 O&M Expenses (000's)	311	
Current Earnings on Total ERGS at Short-Term Debt		
Rate	$5,824	-
Adjustment to Return Requirement for Total ERGS		
Earning at Short-Term Debt Rate	0.07%	-
Adjusted Percent Return Requirement on Average Net		
Investment Rate Base	9.08%	9.09%

Revenue Requirement

On the basis of the findings in this order, a $16,248,000 increase in electric utility revenues and a $7,781,000 increase in natural gas utility revenues are reasonable for the purpose of determining reasonable and just rates in this proceeding and are computed as follows:

	Electric	Natural Gas
Pro Forma Return on Average Net Investment Rate		
Base at Present Rates	6.77%	5.40%
Required Return on Average net Investment Rate Base	9.08%	9.09%
Earnings Deficiency as a Percent of Average Net		
Investment Rate Base	2.31%	3.69%
Average Net Investment Rate Base (000's)	$421,081	$126,241
Amount of Earnings Deficiency on Average Net		
Investment Rate Base (000's)	$9,727	$4,658
Revenue Deficiency to Provide for Earnings		
Deficiency Plus Federal and State Income Taxes		
(000's)	$16,248	$7,781

Gas Cost Recovery Mechanism

On January 15, 1999, the Commission authorized an incentive GCRM for MGE that became effective November 1, 1999. In this docket, MGE and Commission staff presented testimony regarding the design of the GCRM, and agreed to certain modifications to the GCRM as well as certain aspects that should remain unchanged. The Commission finds the following to be reasonable:

1. The commodity adder shall be changed from the current level of 3.12 percent to 1.6 percent.

2. MGE shall continue to use the gas supply plan method for determining the commodity benchmark.

3. Savings and losses shall be shared on a 60/40 ratepayer/shareholder basis.

4. Shareholder gains and losses shall be limited to $2 million.

5. A deadband equal to the rolling four-year average capacity release/opportunity sales revenue, in which all gains and losses will flow to ratepayers, shall be implemented.

6. Balancing costs shall be included in the incentive mechanism.

7. MGE shall file results by March 31 of the following year.

8. Changes will be effective with the start of the next gas year, November 1, 2008.

Demand-Side Management

Greenhouse Gas Emission Reductions

Intervenor Robert Owen proposed that the Commission take action to encourage MGE to pursue greenhouse gas (GHG) emission reductions through energy efficiency and renewable resource programs. These proposed actions include developing a system to track and report GHG emissions on a quarterly basis, allowing rate base treatment for energy efficiency and renewable resource measures, providing MGE the opportunity to earn an enhanced rate of return on energy efficiency and renewable resource investments, and creating a revenue decoupling mechanism. Although the Commission recognizes the urgency in addressing GHG emissions, it is not appropriate to require any specific actions of MGE in this rate case. The Governor's Global Warming Task Force is in the process of assessing a broad range of potential actions to reduce GHG emissions. Additionally, Act 141 requires the Commission to hold periodic proceedings to set targets, priorities, and goals for energy efficiency and renewable resource programs. It is appropriate to address the merits of Mr. Owen's proposals, as well as other possible approaches, within the context of these ongoing initiatives.

Customer Service Conservation Activities

MGE first proposed customer service conservation activities before information regarding the statewide energy efficiency programs was available. Now that the statewide energy efficiency programs have been defined, before MGE modifies its customer service conservation offerings, it must inform Commission staff of the proposed changes and receive Commission staff's acceptance of the changes. As in the past, it is reasonable for MGE to work with Commission staff to develop measures of success for its 2008 customer service conservation activities, using 2007 measures of success as a starting point.

Electric Cost of Service

Witnesses for MGE, WIEG, the Citizens' Utility Board (CUB), and Commission staff testified regarding cost-of-service issues. Testimony presented continued to question the appropriate allocator to use for the allocation of production costs. Both WIEG and CUB agreed that more information about which allocator to use for assigning production costs is needed and requested that the Commission direct MGE to collect information on a more appropriate production capacity allocator prior to its next rate case. The Commission agrees that re-examining the production cost allocator is needed.

Electric Revenue Allocation and Rate Design

MGE and Commission staff proposed complete electric revenue allocations in this docket. CUB argued for a lower revenue allocation for residential customers. WIEG argued for a lower revenue allocation for Cp-1 and Sp-4 customer classes. Both MGE and the Commission staff used electric cost-of-service studies and other factors such as rate comparisons and bill impact information in their proposed electric revenue allocations. The Commission continues to rely on the results of electric cost-of-service studies along with the other information presented in this proceeding as a guide in determining revenue allocation and setting rates.

The Commission finds that the Commission staff's proposed electric revenue allocation and rate design, as adjusted for the final revenue requirement, are reasonable. The approved revenue allocation and rate design take into account established rate relationships, customer bill impacts for both high and low energy use customers of all classes, and the relationship of tariff charges to marginal energy cost.

Revenue allocation must consider factors other than simply the cost-of-service results. These factors include customer bill impacts, marginal energy cost, and rate comparability with other utilities in Wisconsin and surrounding states. Based on the overall weighing of these factors, it is reasonable to assign the electric revenue changes as shown in Appendix B with lower than average increases for all of the residential customer classes and higher than average increases for the commercial and industrial classes. The electric rates also shown in Appendix B are reasonable and appropriately reflect the Commission's consideration of all of these factors.

Act 141 Costs in Base Rates

The Act 141 costs that are included in MGE's electric rates for the 2008 test year total $4,331,000. Act 141 defines ‘large energy customers‘ as a customer of an energy utility that owns or operates a facility in the energy utility's service area, that has an energy demand of at least 1,000 kilowatts of electricity per month or of at least 10,000 decatherms of natural gas per month and that, in a month, is billed at least $60,000 for electric service, natural gas service, or both, for all of the facilities of the customer within the energy utility's service territory. Act 141 freezes the amount of energy conservation costs these customers must pay at the level paid in 2005. To implement this requirement, the Commission must determine how much Act 141 costs are included in the base rates for large customers. MGE has ‘large energy customers‘ that receive service under the Cg-1, Cg-2, Cg-6, Cp-1, Sp-3, and Sp-4 rate tariffs. Since the Cp-1, Sp-3, and Sp-4 rates serve only ‘large energy customers,‘ these classes should only pay the specific conservation costs associated with public benefits that they paid in 2005. These amounts are approximately $0.00001, $0.00002 and $0.00002 per kWh, respectively. The Cg-1, Cg-2, and Cg-6 rates that serve a mixture of ‘large energy customers‘ and non-large customers must be treated differently because Act 141 costs are built into the base rates for these classes. The Act 141 costs in base rates for the non-large customers in the Cg-1, Cg-2, and Cg-6 rate classes total $0.00163 per kWh. Based on the Act 141 limits, the large customers in the Cg-1, Cg-2, and Cg-6 rate classes will pay the specific conservation costs associated with public benefits that they paid in 2005, less the authorized $0.00163 per kWh Act 141 cost already included in the base rates. For the ‘large energy customers‘ in the Cg-1, Cg-2, and Cg-6 rate classes, the amounts they paid in 2005 are approximately $0.00005, $0.00002 and $0.00002 per kWh, respectively. The electric rates shown in Appendix B, along with the customer specific amounts identified above as Act 141 costs, are reasonable.

Buyback Rates

MGE proposed to reduce the on-peak standard electric buyback rate by 24 percent and the off-peak rate by 31 percent. Commission staff proposed to reduce the on-peak rate by 20 percent, but to increase the off-peak rate by 6 percent. The Commission finds that the buyback rates proposed by the Commission staff are reasonable.

Experimental Photovoltaic Buyback Rate

MGE proposed a new buyback rate schedule for customer-owned photovoltaic systems, with the objective of encouraging the installation of new solar electric installations. The cost of the electric energy purchased under the new service schedule will be included in MGE's green pricing program. The Commission finds that the proposed Pg-4 Experimental Photovoltaic Parallel Generation service schedule is reasonable.

Green Pricing Rate

MGE has a voluntary green pricing program with a rate premium of 2.68[per kWh. Based upon an analysis of the incremental costs incurred to purchase renewable energy, MGE proposed to reduce the premium to 1[per kWh. The Commission finds that the green pricing premium proposed by MGE is reasonable.

Long-Term Green Pricing Rates

MGE proposed a provision in its green pricing program for business customers that would allow customers to receive this service for a multi-year term. This program would allow customers to lock-in MGE's proposed 1[per kWh green pricing premium for periods of up to ten years. MGE's witness testified that this proposal was designed to allow MGE to accommodate the requirement that renewable energy purchases made by the state of Wisconsin pursuant to Act 141 be made under arrangements that include terms of at least ten years.

Commission staff testified that MGE's proposed 1[green pricing premium may not fully recover MGE's incremental costs of procuring renewable energy increases in the future. Commission staff also expressed a concern that if such an outcome occurs, non-participating customers would subsidize participating customers that had locked into a fixed long-term premium below the incremental cost. Commission staff also expressed concern about potential unfair competition if a utility subsidizes its competitive green pricing offerings with revenues from monopoly utility services.

The Commission finds that MGE's proposal is reasonable because it is necessary to accommodate purchases of renewable energy by the state of Wisconsin pursuant to Act 141. The final date when business customers may sign up for the program is the end of the test year, December 1, 2008. MGE shall provide the Commission with an annual report showing an analysis of the incremental cost MGE incurs to purchase renewable energy, using the same methodology MGE used in this proceeding.

Innovative Rate Options for Residential Customers

CUB proposed to continue its collaborative work with MGE to investigate innovative residential rate options such as inverted block rates, new TOD rates, and other rate options that promote energy conservation. The Commission accepts this proposal, and directs MGE to include Commission staff in the collaborative meetings to investigate these alternative rate structures.

Electric Rate Tariff Changes

MGE proposed several miscellaneous electric tariff changes in Exhibit 22. These changes include the incorporation of ballast energy usage in SL-1, SL-2, SL-3, and OL-1 rates, the elimination of references to the Cs-1 and Cs-2 rate classes from tariff Sheet E37, and the changes to the BGS rider on tariff sheets E40 and E40.01. The Commission authorizes the miscellaneous electric tariff changes proposed by MGE. These changes are shown in Appendix B.

Electric and Natural Gas Service and Extension Rule Changes

MGE proposed several miscellaneous natural gas and electric tariff changes in Exhibits 5 and 22. These changes include revisions to the Distribution Extension Embedded Cost Allowances, an increase in the insufficient funds charge from $10 to $20, a reconnection charge for customers that illegally reconnect their own service, and changes to tariff sheets E60-E74 and G44-G54 to remove any duplication of Wisconsin Administrative Code requirements and improve clarity. The Commission authorizes these proposed changes to MGE's electric and natural gas service and extension rule tariffs as shown in Appendices B and C.

Natural Gas Rate Design

Two complete natural gas rate designs were submitted in this proceeding, one by MGE and one by Commission staff. They differ primarily in the treatment of customer charges. MGE favored collecting more of its revenues through fixed charges. In this case, MGE proposed raising customer charges for the residential class from the present $9.50 per month to $15.21. MGE asserted that there is a trend toward lower use per customer and that higher customer charges would reduce MGE's revenue volatility.

Commission staff disagreed that the apparent trend in lower use per customer would justify the proposed customer charge increase. Commission staff agreed that there is a trend toward lower use per customer, but that its effect is subsumed in the forward test year sales forecast used in the test year. Commission staff proposed a $10.25 per month customer charge, which is equivalent to the highest customer charge that the Commission has approved.

MGE proposed raising the small commercial class, GSD-1, customer charge from $18.55 per month to $22.81, decreasing the medium commercial class, GSD-2, from $105.00 per month to $101.96, and leaving the large commercial class, GSD-3, customer charge unchanged. Commission staff proposed leaving all the commercial class rates unchanged, both with respect to customer charges and distribution charges because of the substantial effect of ascribing Act 141 revenues in this case. Commission staff also noted that the Act 141 prescribed increases negatively impact the crossover points between classes, the points at which it becomes economically advantageous to change classes. This can result in poor public policy by giving customers an incentive to increase their volumes through wasteful use in order to qualify for a higher volume class with a lower rate. Commission staff proposed that after the Commission determined the final revenue requirement, the change in the final revenues be used in final rate design to reestablish the proper crossover points.

MGE proposed no changes in the customer charge levels for both the Interruptible Generation, IGD-1, and Steam and Power Generation, SP-1, classes. The Commission staff rate design also leaves these customer charges unchanged.

MGE proposed raising the Season Off-Peak Distribution customer charge from $45.63 to $53.23 per month. The Commission staff rate design does also.

The Commission staff rate design alternative did not materially differ further from MGE's proposed rate design with regard to distribution margin rates, administrative charges, IS-1 and FS-1 supply charges, and telemetering and balancing charges.

MGE proposed multiple changes to the company's gas service rules and regulation sheets, as shown in Appendix C. These changes consist of minor revisions to natural gas tariff Sheets G44 through G54 and include the removal of duplicate references to the Wisconsin Administrative Code, the realignment of some of the sections to be more consistent between gas and electric tariffs, and some clarifying language changes. In addition, MGE proposed increasing the insufficient funds charge from $10 to $20, consistent with the authorized increase in the Electric Service Rules.

The Commission staff rate design alternative is based on a pair of Cost-of-Service Studies (COSS), the demand-oriented COSS-A and the commodity-oriented COSS-B. Commission staff's rate design is appropriate when adjusted proportionately for the final revenue requirement. Revenue allocation in this case was determined by considering factors other than simply the cost of service results. These factors include rate stability, avoidance of undue discrimination and subsidies, fairness between system sales and transportation customers, customer bill impacts, incentives to conserve, and rate comparability with other utilities in Wisconsin and surrounding states. Based on the overall weighing of these factors and maintaining interclass stability in particular, it is reasonable to assign the gas revenue changes as shown in Appendix C. The natural gas rates shown in Appendix C are reasonable and appropriately reflect the Commission's consideration of all of these factors.

Other Natural Gas Rates and Rules

The minor revisions to tariff Sheets G44 through G54, and an increase in the insufficient funds charge that is consistent with the Electric Service Rules, as shown in Appendix C, are reasonable.

Effective Date

The test year commences on January 1, 2008. Under Wis. Stat. § 196.40, an order or determination of the Commission shall take effect 20 days after the order or determination has been filed and served on the parties to the proceeding unless the Commission specifies a different effective date in the order or determination.

The Commission finds it reasonable for this decision to be effective the later of one day after the date of mailing or January 1, 2008, provided that the rates are filed with the Commission and placed in all offices and pay stations of the utility by that date. If the authorized rates and rules are not placed in all offices and pay stations by January 1, 2008, the rates shall become effective on the date that the rates are filed with the Commission and placed in all offices and pay stations.

Order

1. This *Final Decision* shall be effective the later of one day after the date of mailing or January 1, 2008, provided that the rates are filed with the Commission and placed in all offices and pay stations of the utility by that date. If the authorized rates and rules are not placed in all offices and pay stations by January 1, 2008, the rates shall become effective on the date the rates are filed with the Commission and placed in all offices and pay stations.

2. MGE shall prepare bill inserts that properly identify the rates authorized in this order. MGE shall distribute these inserts to customers with the first billing containing the rates authorized in this order and shall file copies of these inserts with the Commission before it distributes the inserts to customers.

3. MGE may substitute, for its existing rates and rules for electric and natural gas utility service, the rate and rule changes contained in Appendices B and C. These changes shall be in effect until the issuance of an order by the Commission establishing new rates and rules.

4. The fuel costs in Appendix D shall be used for monthly monitoring of MGE's fuel costs, pursuant to Wis. Admin. Code ch. PSC 116.

5. MGE shall calculate the return on carrying costs on ERGS construction expenditures at the short-term debt rate.

6. MGE may escrow the billing charges from its affiliate MGEPER for its share of ERGS O&M expenses, which began in 2007. MGE also may continue to escrow billing charges from MGEPER for its share of carrying costs on ERGS construction expenditures, management fees, and community impact mitigation costs.

7. MGE shall continue accounting for allowable electric and natural gas conservation expenditures on an escrow basis.

8. The GCRM shall be modified as discussed in the Opinion section of this *Final Decision*. The modifications shall take effect November 1, 2008.

9. MGE shall inform Commission staff of any proposed changes to its customer service conservation activities and receive Commission staff's acceptance of the changes before implementing them.

10. MGE shall work with Commission staff to develop measures of success for its 2008 customer service conservation activities, using 2007 measures of success as a starting point.

11. MGE shall work with Commission staff to collect more information about the production cost allocator and shall submit this information in its next rate case application.

12. MGE is authorized to implement the Pg-4 Experimental Photovoltaic Parallel Generation service schedule.

13. MGE is authorized to revise its green pricing programs to include a premium of 1[per kWh.

14. MGE is authorized to implement its proposed changes to the Business Renewable Energy Program service schedule. The final date when business customers may sign up for the program is December 31, 2008.

15. MGE shall provide the Commission with an annual report showing an analysis of the incremental cost MGE incurs to purchase renewable energy using the same methodology MGE used in this proceeding.

16. Jurisdiction is retained.

Dated at Madison, Wisconsin, December 14, 2007

Notice of Appeal Rights

Notice is hereby given that a person aggrieved by the foregoing decision has the right to file a petition for judicial review as provided in Wis. Stat. § 227.53. The petition must be filed within 30 days after the date of mailing of this decision. That date is shown on the first page. If there is no date on the first page, the date of mailing is shown immediately above the signature line. The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review. Notice is further given that, if the foregoing decision is an order following a proceeding which is a contested case as defined in Wis. Stat. § 227.01(3), a person aggrieved by the order has the further right to file one petition for rehearing as provided in Wis. Stat. § 227.49. The petition must be filed within 20 days of the date of mailing of this decision. If this decision is an order after rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not an option. This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable. Revised 9/28/98

APPENDIX A (CONTESTED)

In order to comply with Wis. Stat. § 227.47, the following parties who appeared before the agency are considered parties for purposes of review under Wis. Stat. § 227.53. Public Service Commission of Wisconsin (*Not a party but must be served*) 610 N. Whitney Way P.O. Box 7854 Madison, WI 53707-7854 MADISON GAS AND ELECTRIC COMPANY Richard K. Nordeng Stafford Rosenbaum LLP PO Box 1784 Madison, WI 53701-1784 CITIZENS UTILITY BOARD Curt F. Pawlisch Kira E. Loehr Cullen Weston Pines & Bach LLP 122 West Washington Avenue, Suite 900 Madison, WI 53703 INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS LOCAL UNION NO. 2304 David Poklinkoski 1602 South Park Street, Room 101 Madison, WI 53715 ROBERT H. OWEN, JR. 1311 Middleton Street Middleton, WI 53562 RENEW WISCONSIN Michael Vickerman 222 South Hamilton Street Madison, WI 53703 WISCONSIN END-USER GAS AND ELECTRIC ASSOCIATION Darcy Fabrizius PO Box 2226 Waukesha, WI 53187-2226 WISCONSIN INDUSTRIAL ENERGY GROUP Steven A. Heinzen Rea L. Holmes Godfrey & Kahn, S.C. 1 East Main Street, Suite 500 Madison, WI 53703 (Phone: 608-284-2244; 608-284-2232)

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Short-Term Interruptible Replacement Service

STIR

AVAILABILITY

Available to any customer taking service under the Is-1 or Is-2 Interruptible Service Riders.

RATE

The Short-Term Interruptible Replacement service charge shall be the greater of (1) the contracted cost of short-term replacement capacity, plus 10 percent for administrative costs, or (2) $1.20 per kW week. All energy associated with STIR service will be billed under the rate schedule applicable to the firm portion of the customer's load.

The customer may negotiate with the Company the maximum they are willing to pay for replacement service. If the replacement service is not available at or below the maximum price the customer is willing to pay, no purchase shall take place.

CONDITIONS OF DELIVERY

1. STIR service is service provided by the Company to allow customers to replace all or part of their load designated as interruptible with firm demand.

2. STIR service may only be purchased by the customer in one-week increments. The customer will be allowed to purchase no more than three weeks of STIR service in any calendar year and no more than one week out of any four continuous week period.

3. The customer must notify the Company no less than one week in advance of the period the customer seeks STIR service to take effect and must specify the kW of STIR service being requested. Customers with less than 500 kW of load designated as interruptible must request STIR service for their entire interruptible load.

4. The Company will use its currently owned or contracted capacity to provide STIR service whenever possible. When additional purchases are required, the Company shall endeavor to purchase the least cost combination of price and quantity which is sufficient to meet the customer's STIR service needs.

Backup Generation Service Rider — Pilot Program

BGS

AVAILABILITY

Service under this voluntary schedule is available to customers on demand-metered rate schedules Cg-1, Cg-2, Cg-4, Cg-6, Sp-3, and Sp-4 who contract for service for an initial period of five years or more. Participation in this program will be limited to a 50 MW total customer load.

If the customer maximum 15-minute demand level falls below 75 kW, the Company will determine if it is reasonable to remove the BGS generator from the customer and discontinue BGS at that site or retain BGS at the customer site and charge for BGS based on the minimum demand volume determined in the rate provision below. Factors such as generator size, potential use of the generator elsewhere, future customer demand, and special usage circumstances will be considered in making this decision. If the Company determines it is appropriate to keep the BGS generator at the customer location, the customer may choose to continue BGS service but must agree to the minimum demand charge as described under the rate provision below.

RATE

All the provisions of the applicable Cg-1, Cg-2, Cg-4, Cg-6, Sp-3, and Sp-4 rate schedules will apply. In addition:

1. Customers taking firm service under this schedule will have an additional charge for backup service applied to the customer maximum 15-minute demand as follows:

a. Customers who initiated service prior to July 1, 2006, will have the charge designated below applied to the greater of the customer maximum 15-minute demand or 75 kW.

b. Customers who initiated service on and after July 1, 2006, will have the charge designated below applied to the greater of the customer maximum 15-demand, 50 percent of the highest customer maximum 15-minute demand experienced by the customer during the time period the customer is served under this rate schedule, or 75 kW.

c. Customers who request redundant on-site BGS capacity, and such added capacity is available to the Company under the existing terms of the tariff, will have the charge designated below applied to the standby-rated capacity of the redundant generator. Redundant on-site BGS capacity in this rate schedule means any BGS generator(s) in addition to the generator(s) deemed appropriate by the Company to supply the customer maximum 15-minute demand at the time of installation.

2. Customers taking interruptible or supplemental service will have an additional charge for backup service applied to the minimum contract firm demand level as identified below.

a. For diesel-fueled generators, $0.04932 per kW per day for continuing contracts. b. For diesel-fueled generators, $0.06575 per kW per day for renewed contracts. c. For natural gas-fueled generators, $0.11507 per kW per day for continuing contracts. d. For natural gas-fueled generators, $0.13151 per kW per day for renewed contracts.

CONDITIONS OF DELIVERY

1. A customer receiving service under this rider must enter into a contract that identifies the size of the generator specified and installed by the Company and the customer's expected annual maximum load.

2. A customer that receives electric service through more than one distribution service feed at a single location (premise) may choose to take backup service under this schedule for all or only some of the service feeds at that location. The Company may require the customer to pay in advance of installation for any additional metering or measurement equipment necessary for the customer to take backup service for less than the entire premise. For firm service customers, backup generation service must be taken for the entire load at each distribution service chosen. For purposes of this schedule, the customer maximum 15-minute demand will be the greatest rate at which electrical energy has been used for the distribution service feeds chosen during any 15 consecutive minutes in the current or preceding 11 billing months. For interruptible and supplemental service customers, backup generation service must be taken for the full amount of the customer's minimum contract firm demand level. For purposes of this schedule, the contract firm demand level will be the customer's contract firm demand level in effect at the time the customer enters into the BGS contract with the Company.

3. The contract will have an initial term of five or more years. At the end of the initial term the contract will be automatically renewed on an annual basis unless written notice from either party is delivered to the other party no later than 180 days prior to the end of the contract term.

4. The authorized rate in effect at the time the initial contract term begins for a customer will remain fixed for that customer for the entire initial contract term, regardless of other changes that may from time to time be approved by the Public Service Commission of Wisconsin. At the end of the initial term, service will be charged at the authorized rate in effect at the time.

5. The Company will work with the customer to determine where to install the generator and associated equipment. The facilities will comply with Wisconsin State Electrical Code, local ordinances, and accepted engineering and planning practices and will be connected to the Company's system over the most direct route as determined by the Company. The Company is responsible for maintaining facilities in compliance with applicable regulations and ordinances that may change over the term of the contract.

6. The customer will provide or will be responsible for the cost of all right-of-way easements and building permits necessary for the Company to connect the generator to the Company's system and to install, maintain, or replace distribution facilities where necessary.

7. The customer will supply the space for the generator and a concrete pad as specified by the Company. The customer will either clear and grade such property and pour the pad or pay the Company to clear and grade such property and pour the pad.

8. The Company is responsible for installation and backfilling as necessary. The customer is responsible for the cost of restoration of the property after the Company has completed installation and backfilling where applicable.

9. If the generator installation requires nonstandard service facilities or if the customer requests nonstandard facilities or design, including but not limited to aesthetics, noise attenuation, exhaust ventilation, or location on the customer's premise, the Company will require the customer to pay a contribution in advance of construction for the cost of the facilities in excess of standard design.

10. The customer will be required to make the Company equipment available and permit entry upon the property by Company personnel at reasonable times for the purposes of testing, maintenance, and replacement of the equipment. The Company will be responsible for testing the generator at least once a year to ensure the equipment is in proper working condition.

11. The Company reserves the right to operate the generator to meet system load requirements.

12. The availability of service under this schedule may be limited at the discretion of the Company. Service under this schedule may be refused if the Company believes the customer presents an unacceptable credit risk or cannot provide or meet suitable generator siting requirements, including physical and environmental restrictions and liability limitations.

13. Service under this schedule will be furnished only in accordance with the Electric Service Rules and Regulations of the Company.

14. Energy furnished under this schedule will not be resold by the Customer.

Residential Renewable Energy Program

RWE-1

AVAILABILITY

Service under this voluntary schedule is available to residential customers on Rate Schedules Rg-1, Rg-2, Rg-3, and Rw-1.

RATE

All of the provisions of the applicable Rg-1, Rg-2, Rg-3, and Rw-1 rate schedules will apply, with the exception that customers served on this rider who:

1. Elect to purchase a block of energy will have a Renewable Energy Charge equal to $0.0100 per kWh multiplied by the contracted monthly kWh block size added to each bill; or

2. Elect to purchase a percent of their energy under this rider will have an incremental energy charge of $0.0100 per kWh applied to the contracted percentage of kWh each billing period.

The charge above is in addition to the monthly energy charges on the customer's standard applicable tariff rate.

All energy purchased under this rider is exempt from fuel cost surcharges and credits.

SPECIAL TERMS AND PROVISIONS

1. Energy produced by renewable energy projects may be limited, and service under this rider may be limited at the discretion of the Company, based on the expected level of renewable energy available.

2. Changes in the weather, renewable energy market, and other factors may result in less renewable power being generated than predicted. Upon review at the end of each calendar year, if annual energy produced and purchased from renewable energy sources was not sufficient to meet actual customer purchases, the Company will refund each currently participating customer, at the time of the review, an amount equal to $0.0100 per kWh multiplied by the difference between the actual renewable energy kWh delivered and the renewable energy kWh the customer committed to purchase.

3. Due to the fact this service is optional and increases utility bills, the Company may limit customer participation in the program based on bill payment and collection histories.

4. The Company may establish minimum block sizes and percentages for participants under this program. Customers who previously took service on this tariff prior to the effective date of the order in Docket 3270-UR-115 at a 150-kWh block size may continue service under this block size unless they subsequently change their service election.

Business Renewable Energy Program

BWE-1

AVAILABILITY

Service under this voluntary schedule is available to commercial and industrial customers on rate schedules Cg-1, Cg-2, Cg-3, Cg-4, Cg-5, Cg-6, Cp-1, Sp-3, Sp-4, Sp-5, Gf-1, Mg-2, MLS, OL-1, SL-1, SL-2, and SL-3 who contract with the Company to purchase a block of renewable energy.

RATE

All of the provisions of the applicable rate schedules will apply, with the exception that customers served on this rider who:

1. Elect to purchase a block of energy will have a Renewable Energy Charge equal to $0.0100 per kWh multiplied by the contracted monthly kWh block size added to each bill; or

2. Elect to purchase a percent of their energy under this rider will have an incremental energy charge of $0.0100 per kWh applied to the contracted percentage of kWh each billing period.

The charge above is in addition to the monthly energy charges on the customers' standard file tariff rate.

All energy purchased under this rider is exempt from fuel cost surcharges and credits.

SPECIAL TERMS AND PROVISIONS

1. Energy produced by renewable energy projects may be limited, and service under this rider may be limited at the discretion of the Company, based on the expected level of renewable energy available.

2. Changes in the weather, renewable energy market, and other factors may result in less renewable power being generated than predicted. Upon review at the end of each calendar year, if annual energy produced and purchased from renewable energy sources was not sufficient to meet actual customer purchases, the Company will refund each currently participating customer, at the time of the review, an amount equal to $0.0100 per kWh multiplied by the difference between the actual renewable energy kWh delivered and the renewable energy kWh the customer committed to purchase.

3. Due to the fact this service is optional and increases utility bills, the Company may limit customer participation in the program based on bill payment and collections histories.

4. The Company may establish minimum block sizes and percentages for participants under this program. If the existing service level is below newly established minimums, customers who previously took service on this tariff prior to the effective date of the order in Docket 3270-UR-115 may continue service under either the block size or percentage level as of that date unless they subsequently change their service election.

5. If a customer desires to lock in the renewables adder rate effective at the time the customer initiates service under this rate schedule, the customer may do so by signing a multiyear contract for service for a period of time up to ten years. Customers who elect this option will remain on service for the term of the contract at the rate effective at the time the contract is entered, regardless of changes from time to time that may be authorized in the rate schedule. Service can be continued after the term of the contract, if available, at the authorized rate that is then effective. Customers who do not elect the contract option will receive service at the currently effective rates, which are subject to change as authorized by the Public Service Commission of Wisconsin.

TABULAR OR GRAPHIC MATERIAL SET FORTH AT THIS POINT IS NOT DISPLAYABLE

Experimental Photovoltaic Parallel Generation

Pg-4

AVAILABILITY

Available to customers in good standing of the Company with their own photovoltaic (PV) electric generation facilities who wish to sell the energy generated by their facility to the Company. Eligibility for this experimental tariff is limited to customers who have had a meter set date for their installation of March 6, 2007, or later.

Customers must be a retail electric customer of the Company and also take service under one of the renewable energy programs (Rate Schedule RWE-1 or BWE-1) at least at the level of AC energy produced by the customer's PV system on an annual basis.

Participation in this experimental tariff will be limited to 150-kW DC of nameplate customer PV generation, to be filled on a first-come, first-served basis as determined by an interconnection agreement for the installation signed by both the customer and the Company. Minimum installation size is 1-kW DC and maximum installation size is 10-kW DC.

RATE

The customer will receive a monthly credit of $0.25/kWh AC for PV energy sold to the Company.

SERVICE COMPATIBILITY

The customer must generate electric power at the same characteristic, voltage, and frequency as the customer receives service from the Company without creating an undue imbalance in the system and will be subject to the same electric service rules as are the general service customers of the Company.

Safety of the physical well-being of all persons will be paramount under all considerations and aspects of the construction, operation, and maintenance of generating equipment operated in parallel with the Company's system.

METERING AND SERVICE FACILITIES

The customer will pay for the cost of rebuilding any Company facilities required to adequately accommodate the parallel generation system and will provide proof of compliance with all applicable local, state, and national electrical and safety codes in writing. These costs may be paid by the customer over a time period not to exceed 24 months from billing by the Company. A finance charge will be added to all amounts not paid within 30 days of billing.

Two utility meters are required for this program and provided by the Company. The customer must provide a suitable two meter socket that meets all codes and standards for grid-connected terrestrial power systems.

INTERCONNECTION FACILITIES

The customer will furnish, install, operate, and maintain facilities such as manual lockable disconnect(s), relays, switches, synchronizing equipment, monitoring equipment, a two-meter socket for the customer generation and billing meters, and control and protective devices designated by the Company as suitable for parallel operation with the Company system. Such facilities and schemes will be reviewed and approved by the Company prior to interconnection. Interconnection equipment designed to isolate the customer's generation from the Company's system will be accessible at all times to authorized Company personnel. All other equipment will be accessible to the Company periodically for routine testing.

Customer generation equipment will be of such design as to prevent undesirable effects upon the operation of standard services or equipment of the Company, its customers, or other utilities or agencies (for example, telephone, radio, or television interference).

In all respects, the generation equipment and its connection to the Company's system will conform to the guidelines and interconnection rules in Wisconsin Administrative Code 119.04.

CONTRACT

The Company will require a ten-year contract specifying technical and operating aspects of the PV system, as specified in the ‘PV Generation Interconnection Agreement (10-kW DC or less)‘. The effective date of this agreement will be the date that the Company signs this agreement. The customer has 12 months from the effective date of this agreement to interconnect and deliver energy to the Company.

Customers have the right to appeal to the PSCW if they believe the contract required by the Company is unreasonable.

LIABILITY OF THE PARTIES

Customer will secure liability insurance that provides protection against claims for damages resulting from (i) bodily injury, including wrongful death, and (ii) property damage arising out of customer's ownership and/or operation of the facility. The limits of the policy will be at least $300,000 per occurrence or prove financial responsibility by another method acceptable and approved in writing by the Company. The failure of the customer or the Company to enforce the minimum levels of insurance does not relieve the customer from maintaining such levels of insurance or relieve the customer of any liability. The customer will provide the Company with a certificate of insurance containing a minimum 30-day notice of cancellation prior to execution of the agreement.

Each of the parties will indemnify and save harmless the other party against any and all damages to persons or property occasioned, without the negligence of such other party, by the maintenance and operation by such parties of their respective lines and other electrical equipment.

ENERGY CREDITS

All renewable energy credits and benefits, emissions allowances, or other renewable energy, air emissions, or environmental benefits for which the PV generation project qualifies under any existing or future applicable law relating to renewable energy projects will be the property of the Company.

Electric Service Rules and Regulations

INFORMATION AVAILABLE TO CUSTOMERS

See Wis. Admin. Code PSC 113.0501.

APPLICATION FOR SERVICE

Application for electrical service will be made at the Company's General Office or at such other locations as may from time to time be authorized by the Company. Application will be accepted in person, by telephone, by e-mail through the Company's Web site (www.mge.com), or by signed application at Company discretion. Service connections and extensions will be made in accordance with filed rules and regulations.

RESPONSIBILITY FOR USE OF SERVICE

1. Receipt of service will make the receiver a customer of the Company, subject to its rates, rules, and regulations, whether service is based on contract, signed application, or otherwise.

2. Subject to its rates, rules, and regulations, the Company will continue to supply service until ordered to discontinue, and the customer will be responsible for payment for all service furnished until discontinued.

3. New occupants of premises previously receiving service must make official application to the Company before commencing the use of service.

4. Customers who have been receiving service must notify the Company when discontinuing service; otherwise, they will be liable for the use of the service by their successors should said successors refuse to pay.

5. Customers assume all responsibility on their side of the point of delivery for the service supplied or taken, as well as for the service installation, appliances and apparatus used in connection therewith, and will save the Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from such service or the use thereof on their side of the point of delivery unless such injury or damage is caused by the negligence of the Company.

DIVERSION OF SERVICE

1. When the Company has sufficient evidence that a customer is obtaining an electrical service in whole or in part by means of devices or methods which stop or interfere with the proper metering of the electrical service being delivered to the premises or otherwise results in unmetered electrical service being delivered to the premises, the customer will be subject to disconnection under Company rules and regulations on Disconnection of Service.

2. Except as limited by law, when such diversion has been discovered by the Company, the customer will be subject to the following:

a. The customer will be required to pay the Company for the estimated losses of revenue occasioned by the diversion for the period that customer has been responsible for paying for electrical service. The Company may, however, waive billing the customer when the projected costs of billing and recovery exceed the amount likely to be recovered.

b. The customer will be required to pay the Company for any and all damages to the Company's equipment due to such diversion.

c. The customer will be required to pay the Company for any and all costs incurred by the Company in investigating and correcting the diversion.

d. The customer will be required to pay for any reconnection charges arising out of the diversion.

e. The customer will be required to pay for the cost of making the installation tamperproof.

f. The Company will bill the customer for the unmetered service, the cost of correcting the problem or damage, the reconnection charges, the cost of making the installation tamperproof, and the cost of investigation. Payment may be due within 24 hours of billing or the customer may be subject to a ten day's notice of disconnection.

g. In the event any tamperproof installation so installed will be the subject of further damage or interference by the customer or customer's permittee, the Company will have the right to terminate service without further notice.

DISCONTINUANCE OF SERVICE

Notice by customers of discontinuance of service will be accepted at the Company's General Office or at other such locations as may from time to time be authorized by the Company. Such notice may be made in person, by telephone, by e-mail, through the Company's Web site (www.mge.com), or in writing.

PREFERRED SERVICE CHARGES

When application is made for electrical service with the request that meters be set or read on or after regular working hours or within the same half working day, a charge per meter will be made. (See Sheet No. E54 for charges.)

DEPOSIT RULE

Considerations for deposit

• For new residential service, see Wis. Admin. Code PSC 113.0402(1)(a)(b)(c). • For existing residential service, see Wis. Admin. Code PSC 113.0402(4)(a)(b)(c). • For new commercial service, see Wis. Admin. Code PSC 113.0403(1)(2)(a)(b)(c)(d)(e). • For existing commercial service, see Wis. Admin. Code PSC 113.0403(5)(a)(b).

Amount of deposit

• For new and existing residential service, see Wis. Admin. Code PSC 113.0402(7)(a)(b)(c). • For new and existing commercial service, see Wis. Admin. Code PSC 113.0403(8)(a)(b)(c).

Deposit interest

• For new and existing residential service, see Wis. Admin. Code PSC 113.0402(9)(a)(b)(c). • For new and existing commercial service, see Wis. Admin. Code PSC 113.0403(9)(a)(b)(c).

Refund of deposit

• Time of refund Payment is considered prompt if made prior to notice of disconnection for nonpayment not in dispute. — For residential service, see Wis. Admin. Code PSC 113.0402(10)(11). — For commercial service, see Wis. Admin. Code PSC 113.0403(10). • Refund at termination of service — For residential service, see Wis. Admin. Code PSC 113.0402(13). — For commercial service, see Wis. Admin. Code PSC 113.0403(12). • Apply deposit to arrearage — For residential service, see Wis. Admin. Code PSC 113.0402(14)(a)(b)(c). — For commercial service, see Wis. Admin. Code PSC 113.0403(13)(a)(b)(c). • Method of refund — For residential service, see Wis. Admin. Code PSC 113.0402(12). — For commercial service, see Wis. Admin. Code PSC 113.0403(11).

Written explanation

• For residential service, see Wis. Admin. Code PSC 113.0402(5). • For commercial service, see Wis. Admin. Code PSC 113.0403(6)(a)(b).

Refusal or disconnection of service

• For residential service, see Wis. Admin. Code PSC 113.0402(8). • For commercial service, see Wis. Admin. Code PSC 113.0403(7).

Review

For residential service only, see Wis. Admin. Code PSC 113.0402(11).

Applicability

• For residential service, see Wis. Admin. Code PSC 113.0402(15). • For commercial service, see Wis. Admin. Code PSC 113/0403(14).

GUARANTEE

Terms and conditions

• For residential service, see Wis. Admin. Code PSC 113.0402(3)(a)(b)(c). • For commercial service, see Wis. Admin. Code PSC 113.0403(4)(a)(b)(c).

Payment terms

• For residential service, see Wis. Admin. Code PSC 113.0402(2). • For commercial service, see Wis. Admin. Code PSC 113.0403(3).

Applicability

The rules as described in Deposit Rule, Guarantee Rule, and Deferred Payment Agreement are not applicable to deposits or guarantees made in connection with financing extensions or other equipment.

DISCONNECTION OF SERVICE

• For residential service, see Wis. Admin. Code PSC 113.0301, 113.0304, and 113.0305. • For commercial service, see Wis. Admin. Code PSC 113.0302.

RECONNECTION OF SERVICE

See Wis. Admin. Code PSC 113.0303.

RECONNECTION CHARGES

See Sheet No. E54 for charges.

Application

• For reconnection of electrical service following disconnection for nonpayment of a required deposit or bills for electrical service. • For reconnection of an electric meter for the same customer on the same premises within one year when disconnection was for reasons other than nonpayment. • A reconnection charge may be applied to utility accounts of disconnected customers who reconnect their own service and the Company must disconnect the customer again.

DEFERRED PAYMENT AGREEMENT

See Wis. Admin. Code PSC 113.0404.

DISPUTE PROCEDURES

See Wis. Admin. Code PSC 113.0407.

CUSTOMER COMPLAINTS

See Wis. Admin. Code PSC 113.0610.

METER READINGS AND BILLING PERIODS

See Wis. Admin. Code PSC 113.0405.

BILLING

See Wis. Admin. Code PSC 113.0406.

In addition, where rental residential dwelling electrical service is in the tenant's name, and the tenant vacates the residential dwelling unit, continued electrical service for such dwelling unit will be placed in the name of the owner or property manager when the Company has no information concerning a new tenant to start service.

The Company will provide the owner or property manager with written notice of its intent to transfer billing responsibility. Such notice will provide the owner or property manager with 15 days to notify the Company of:

1. The name of the customer who should be placed in service, such service date not to be later than 15 days from the notice mailing date; or

2. That electrical service to the premises should be terminated. The owner or property manager must affirm to the Company that such termination will not endanger human health or life or cause damage to property during the period of disconnection.

PAYMENTS

Failure to receive a bill does not relieve the customer of the obligation to make payment by the due date.

Customers who fail to make payment by the due date are also subject to the application of the procedures provided in the Company's filed rules covering disconnection of electrical service. Payment to a third party, other than to an authorized pay station, does not constitute payment to the Company. MGE will not be responsible for disputes regarding payments to third parties which are not authorized pay stations.

When a payment made to the Company and credited to a customer's account is reversed for insufficient funds, a charge plus applicable late payment charges will be applied to the customer's account. (See Sheet No. E54 for the charge.)

LATE PAYMENT CHARGE

See Wis. Admin. Code PSC 113.0406(1)(5).

BUDGET PAYMENT PLAN

See Wis. Admin. Code PSC 113.0406(5).

METER INSTALLATION AND SEALING OF METERS

1. Per PSC 113.0809, electric meters are furnished by the Company and set without charge; however, electric permits are required by the authorized inspector in the area. Affidavits are permissible for state, county, and municipal applications, as allowed by such authorities, or in those areas where inspectors are not assigned.

2. Per PSC 113.0808, meters are sealed by the Company, and such seals will not be broken or tampered with without the consent of the Company except in cases of emergency. The Company should be notified within 48 hours after the seal has been broken.

METER TESTS

All meter tests, records, and billing adjustments for meters with errors greater than prescribed limits are made in accordance with rules and regulations governing electrical service by public utilities prescribed by the Commission (PSC 113.0901-0926).

BILLING DEAD METERS AND METERS SHOWING UNDER-REGISTRATION

See Wis. Admin. Code PSC 113.0924.

REFUNDS FOR FAST METERS

See PSC 113.0924.

ACCESS TO CUSTOMERS' PREMISES

Authorized agents of the Company will have access to customers' premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, making investigations, removing Company property, or for any other purpose incident to providing service. Refusal or failure to provide authorized personnel access to Company equipment may result in disconnection of service. See Wis. Admin. Code PSC 113.0301(1)(k) and 113.0302(2)(h).

BILLING FOR GROUNDS

1. Subject to the Company's rules setting forth the method of determining a reduced rate herein authorized, if an accidental ground is found on a customer's wiring or equipment, the Company will estimate the kilowatt-hours lost and bill for them at a reduced rate not less than the generated or purchase cost of the energy, but no such adjustment will be made for energy supplied after the customer has been notified and has had an opportunity to correct the condition. Any demand (kilowatt) caused by an accidental ground will be billed at a rate lower than that filed for the class of service involved. The Company will notify the customer of the ground whenever it is found or suspected.

2. The Company assumes no responsibility for injuries, damages, or losses resulting from grounds in customers' installations and has the right to disconnect a customer who fails to eliminate a ground after reasonable notice. The Company will conduct tests to ascertain the existence of a ground but will not investigate or test a customer's installation for the purpose of determining the location or the nature of such defects.

POWER FACTOR CORRECTION RULE

1. When fluorescent, neon, zeon, or other hot or cold cathode types of gaseous tube lighting having similar power factor characteristics are installed and are used for illumination or decorative purposes as a major lighting source, the customer will furnish, install, and maintain, at their own expense, corrective apparatus designed to maintain, at not less than 90 percent lagging, the power factor of each unit of such equipment or groups of such equipment controlled as a unit by a single switch or its equivalent which controls only such unit.

2. When fluorescent, neon, zeon, or other hot or cold cathode types of gaseous tube lighting having similar power factor characteristics are installed and are used for advertising purposes, the customer will furnish, install, and maintain, at their own expense, equipment designed to correct the power factor of the unit to at least 85 percent lagging except that no correction will be required for any complete sign supplied from a single auxiliary transformer rated at 225-volt amperes or less.

3. The determination of power factor will be made by the wattmeter-voltmeter-ammeter method.

4. To be considered advertising, the tubing must contain a message showing either a configuration of letters, numerals, characters, or distinctive trademarks.

5. The Company may refuse or discontinue service to any such installation made after September 2,1941, until the customer has complied with the provisions of this rule.

CUSTOMER'S RESPONSIBILITY FOR COMPANY'S EQUIPMENT

The customer will be responsible for all damage to the Company's equipment caused by the customer or their permittees, including compensation for consumed energy not recorded on the meter. Issued: December x, 2007 Effective: January 1, 2008 PSCW Authorization: By Order in Docket 3270-UR-115 dated December?, 2007; File No. 3270. Issued: December x, 2007 Effective: January 1, 2008 PSCW Authorization: By Order in Docket 3270-UR-115 dated December?, 2007; File No. 3270. Issued: December 29, 2000 Effective: January 1, 2001 PSCW Authorization: By Order in Docket 3270-UR-110 dated December 21, 2000. Issued: December 29, 2000. Reissued February 28, 2003, due to punctuation correction. Effective: January 1, 2001 PSCW Authorization: By Order in Docket 3270-UR-110 dated December 21, 2000.

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Appendix C

INFORMATION AVAILABLE TO CUSTOMERS

See Wis. Admin. Code § PSC 134.05.

APPLICATION FOR SERVICE

Application for gas service will be accepted at the Company's General Office or at such other locations as may from time to time be authorized by the Company. Application may be made in person, by telephone, by e-mail, through the Company's Web site (www.mge.com), or by signed application at the discretion of the Company. Service connections and extensions will be made in accordance with filed rules and regulations.

RESPONSIBILITY FOR USE OF SERVICE

Receipt of service will make the receiver a customer of the Company, subject to its rates, rules, and regulations, whether service is based upon contract, signed application, or otherwise.

Subject to its rates, rules, and regulations, the Company will continue to supply service until ordered to discontinue, and the customer will be responsible for payment for all service furnished until discontinued.

New occupants of premises previously receiving service must make official application to the Company before commencing the use of service.

Customers who have been receiving service must notify the Company when discontinuing service; otherwise, they will be liable for the use of the service by their successors should said successors refuse to pay.

Customers assume all responsibility on the customer's side of the point of delivery for the service supplied or taken, as well as for the service installation, appliances, and apparatus used in connection therewith, and shall save the Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from such service or the use thereof on the customer's side of the point of delivery unless such injury or damage is caused by the negligence of the Company.

DIVERSION OF SERVICE

When the Company has sufficient evidence that a customer is obtaining a gas service in whole or in part by means of devices or methods which stop or interfere with the proper metering of the gas service being delivered to the premises or otherwise results in unmetered gas service being delivered to the premises, the customer shall be subject to disconnection under the Company's rules and regulations on disconnection.

Except as limited by law, when such diversion has been discovered by the Company, the customer shall be subject to the following:

1. The customer will be required to pay the Company for the estimated losses of revenue occasioned by the diversion for the period that customer has been responsible for paying for utility service. The Company may, however, waive billing the customer when the projected costs of billing and recovery exceed the amount likely to be recovered.

2. The customer may be required to pay the Company for any and all damages to the Company's equipment due to such diversion.

3. The customer may be required to pay the Company for any and all costs incurred by the Company in investigating and correcting the diversion.

4. The customer may be required to pay for any reconnection charges arising out of the diversion.

5. The customer may be required to pay for the cost of making the installation tamper proof.

6. The Company may bill the customer for the unmetered service, the cost of correcting the problem or damage, the reconnection charges, the cost of making the installation tamper proof, and the cost of investigation. Payment may be due within 24 hours of billing or the customer may be subject to an eight-day notice of disconnection.

7. In the event any tamper-proof installation so installed shall be the subject of further damage or interference by the customer or customer's permittees, the Company shall have the right to terminate service without further notice.

DISCONTINUANCE OF SERVICE

Notice by customers of discontinuance of service will be accepted at the Company's General Office or at other such locations as may from time to time be authorized by the Company. Such notice may be made in person, by telephone, by e-mail, or through the Company's website (www.mge.com), or in writing.

PREFERRED SERVICE CHARGES

When application is made for gas service with the request that meters be set or read after regular working hours or within the same half working day, a charge of $10 per meter will be made. If the request is for a weekend or holiday, the charge will be $20 per meter.

DEPOSIT RULE

Considerations for deposit

• For new residential service, see Wis. Admin. Code PSC 134.061(1)(a)(b)(c). • For existing residential service, see Wis. Admin. Code PSC 134.061(4)(a)(b)(c). • For new commercial service, see Wis. Admin. Code PSC 134.0615(1)(2)(a)(b)(c)(d)(e). • For existing commercial service, see Wis. Admin. Code PSC 134.0615(5)(a)(b).

Amount of deposit

• For new and existing residential service, see Wis. Admin. Code PSC 134.061(7)(a)(b). • For new and existing commercial service, see Wis. Admin. Code PSC 134.0615(8)(a)(b).

Deposit interest

• For new and existing residential service, see Wis. Admin. Code PSC 134.061 (9)(a)(b)(c). • For new and existing commercial service, see Wis. Admin. Code PSC 134.0615(9)(a)(b)(c).

Refund of deposit

• Time of refund — For residential service, see Wis. Admin. Code PSC 134.061(10)(11). Payment is considered prompt if made prior to notice of disconnection for nonpayment not in dispute. — For commercial service, see Wis. Admin. Code PSC 134.0615(10). Payment is considered prompt if made prior to notice of disconnection for nonpayment not in dispute. • Refund at termination of service — For residential service, see Wis. Admin. Code PSC 134.061(13). — For commercial service, see Wis. Admin. Code PSC 134.0615(12). • Apply deposit to arrearage — For residential service, see Wis. Admin. Code PSC 134.061(14)(a)(b)(c). — For commercial service, see Wis. Admin. Code PSC 134.0615(13)(a)(b)(c). • Method of refund — For residential service, see Wis. Admin. Code PSC 134.061(12). — For commercial service, see Wis. Admin. Code PSC 134.0615(11).

Written explanation

• For residential service, see Wis. Admin. Code PSC 134.061(5). • For commercial service, see Wis. Admin. Code PSC 134.0615(6)(a)(b).

Refusal or disconnection of service

• For residential service, see Wis. Admin. Code PSC 134.061(8). • For commercial service, see Wis. Admin. Code PSC 134.0615(7).

GUARANTEE

Terms and conditions

• For residential service, see Wis. Admin. Code PSC 134.061(3)(a)(b)(c). • For commercial service, see Wis. Admin. Code PSC 134.0615(4)(a)(b)(c).

Payment terms

• For residential service, see Wis. Admin. Code PSC 134.061(2). • For commercial service, see Wis. Admin. Code PSC 134.0615(3).

Applicability

The rules as described in Deposit Rule, Guarantee Rule, and Deferred Payment Agreement are not applicable to deposits or guarantees made in connection with the financing of extensions or other equipment.

DISCONNECTION OF SERVICE

• For residential service, see Wis. Admin. Code § PSC 134.062; § PSC 134.0624; and § PSC 134.0625. • For commercial service, see Wis. Admin. Code § PSC 134.0622.

RECONNECTION OF SERVICE

See Wis. Admin. Code § PSC 134.0623.

RECONNECTION CHARGES

From 8 a.m. to 4:30 p.m., Monday through Friday, except holidays: $30. All other times: $45.

Application

• For reconnection of gas service following disconnection for nonpayment of a required deposit or bills for gas utility service. • For reconnection of gas service for the same customer upon the same premises within one year when disconnection was for reasons other than nonpayment.

DEFERRED PAYMENT AGREEMENT

See Wis. Admin. Code § PSC 134.063.

DISPUTE PROCEDURES

See Wis. Admin. Code § PSC134.064.

CUSTOMER COMPLAINTS

See Wis. Admin. Code § PSC 134.17.

APPLICATION OF RATES

The schedules of rates apply to gas furnished to one customer at one location for one class of service through one meter. The schedules of rates is based on delivering and billing service to the ultimate user for retail service only and does not permit resale or redistribution.

Where a single large commercial, industrial, or institutional customer occupies more than one unit of space in the conduct of the same business, each separate unit will be metered separately and considered a distinct customer, unless the customer makes the necessary provisions to permit metering of all gas used for each class of service in the various units at a single metering location. This rule shall apply only where the units are located on contiguous property with no intervening public property or private property controlled by others. Only one service connection will be provided for each class of service furnished, and the metering location shall be as close as possible to the point of service entrance.

In those cases where, at the Company's election, two or more meters are installed at a single metering location on the same premises for the same customer for the same class of service, the amount of gas supplied through all such meters will be combined in arriving at the total charge, and the minimum bill will be the same as though one meter was installed.

A 'month' does not refer to a calendar month, but shall mean the period between any two scheduled consecutive readings of the meters by the Company.

When the Company is unable to obtain the reading of the meter or meters after reasonable effort, the fact will be plainly indicated on the monthly bill and an estimate may be made and so indicated on the bill.

Claims of errors should be made immediately upon receipt of bill.

METER READINGS AND BILLING PERIODS

See Wis. Admin. Code § PSC 134.12.

BILLING

See Wis. Admin. Code § PSC 134.13.

In addition, where rental residential dwelling gas service is in the tenant's name, and the tenant vacates the residential dwelling unit, continued gas service for such dwelling unit will be placed in the name of the owner or property manager when the Company has no information concerning a new tenant to start service.

The Company will provide the owner or property manager with written notice of its intent to transfer billing responsibility. Such notice will provide the owner or property manager with 15 days to notify the Company of:

1. The name of the customer who should be placed in service, such service date not to be later than 15 days from the notice mailing date; or

2. That gas service to the premises should be terminated. The owner or property manager must affirm to the Company that such termination will not endanger human health or life or cause damage to property during the period of disconnection.

PAYMENTS

Failure to receive a bill does not relieve the customer of the obligation to make payment by the due date.

Customers who fail to make payment by the due date are also subject to the application of the rules covering disconnection of gas service. Payment to a third party, other than to an authorized pay station, does not constitute payment to the Company. MGE will not be responsible for disputes regarding payments to third parties which are not authorized pay stations.

When a payment made to the Company and credited to a customer's account is reversed for insufficient funds, a charge of $10 plus applicable late payment charges will be applied to the customer's account.

LATE PAYMENT CHARGE

See Wis. Admin. Code § PSC 134.13(1)(j).

BUDGET PAYMENT PLAN

See Wis. Admin. Code § PSC 134.13(5)(a)-(g).

METER INSTALLATION AND SEALING OF METERS

Gas meters are furnished by the Company and set without charge; however, gas space-heating installations require an authorized gas permit in the city of Fitchburg, city of Madison, city of Monona, village of Maple Bluff, village of Shorewood Hills, village of Waunakee, town of Blooming Grove, town of Madison, and town of Westport. All other areas require no gas space-heating permits.

Meters are sealed by the Company, and such seals shall not be broken or tampered with without the consent of the Company except in cases of emergency. The Company should be notified within 48 hours after the seal has been broken.

METER TESTS

Routine tests of gas meters are made in accordance with the rules prescribed by the Public Service Commission of Wisconsin.

BILLING DEAD METERS AND METERS SHOWING UNDER-REGISTRATION

See Wis. Admin. Code § PSC 134.14.

REFUNDS FOR FAST METERS

See Wis. Admin. Code § PSC 134.14.

ACCESS TO CUSTOMERS' PREMISES

Authorized agents of the Company shall have access to customers' premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, making investigations, removing Company property, or for any other purpose incident to providing service.

CONTINUITY OF SERVICE

The Company will use reasonable diligence to provide an uninterrupted and regular supply of service, but it shall not be liable for any interruptions, deficiencies, or imperfections of service not due to its own negligence. The Company may temporarily suspend the delivery of service when necessary for the purpose of making repairs, changes, and improvements upon any part of its system.

The Company shall not be liable for any losses, injuries, or damages to persons or property due to disconnection of service in accordance with the disconnection rules.

LOCATION OF METERS, PRESSURE REGULATORS, AND SHUTOFFS

1. The meters, pressure regulators, and master shutoff valve shall be installed above ground outside of buildings where applicable as set forth below under ‘Installation of Service Laterals‘; otherwise, at the point of service entrance inside the building at a location prescribed by the Company. This equipment shall be furnished and installed by the Company.

2. Meters installed inside of buildings shall be located as close as possible to the point of service entrance.

3. The customer shall provide ready access for utility employees to meter, pressure regulator, and master shutoff valve locations.

4. Gas meters, pressure regulators, and main shutoff valves shall not be installed in bedrooms, closets, bathrooms, coal bins, over doors, in very damp places, under combustible stairways, in unventilated or inaccessible places; closer than three feet to sources of ignition including furnaces and water heaters; near unprotected electric wiring or devices; in the proximity of belts, shafting, engines, or machinery; in locations where material or equipment-handling operations are carried on; in rooms which are locked; or in places dangerous to meter readers.

5. In all instances, the customer shall furnish, own, and maintain the house piping from the outlet of the meter or pressure control installation, whichever is further down stream, to the utilization equipment. In cases of multiple meter installations, a permanent tag designating the area of utilization (such as an apartment or office number) shall be attached to the house piping at the meter location. Where a concrete slab or footing is necessary for the support of the meter, pressure regulator, and associated devices, it will be the responsibility of the customer to provide such slab or footing satisfactory to the Company.

RELOCATION OF METERS, PRESSURE REGULATORS, AND SHUTOFFS AT CUSTOMER REQUEST

When requested by the customer for reasons other than set forth below in ‘Installation of Service Laterals,‘ gas meters, pressure regulators, and master shutoff valve will be relocated from inside to outside of buildings to a location approved by the Company at no cost to the customer provided that the riser for the pressure regulators and meters is located within ten feet either side of the existing service lateral.

When the location of the riser is more than ten feet either side of the existing service lateral, the Company will require payment equal to the actual total cost of moving the pipe.

In all instances, the customer will be responsible for reconnecting the house piping.

PRESSURE

Standard pressure

The standard pressure at the outlet of service meters is 8‘ of water column. The deviations from standard pressure shall not exceed the amounts set forth in Wis. Admin. Code § PSC 134.23.

High-pressure service

Pressures in excess of the standard pressure set forth above will be provided only upon written request of the customer and subject to any or all of the following conditions:

1. Higher than standard pressure is available at the customer's premises or may be made available in accordance with the filed extension rules.

2. Higher than standard pressure is required for proper operation or economical operation of the customer's utilization equipment

3. The customer shall provide the Company with information as to the quantity of use, the purpose for which used, and the type of gas utilization equipment.

4. The Company may require that such pressure shall conform to the pressures made available to other customers presently served from distribution facilities with similar pressure characteristics.

5. The higher than standard pressure shall be agreed upon between the customer and the Company, and the maximum pressure variation shall not exceed 15 percent of the agreed-upon pressure.

6. The customer has satisfied municipal requirements regarding house piping at other than standard pressure and has any permits, etc., required.

Measurement

For the purpose of correcting high-pressure gas measurements, the following values will be used.

Temperature Base	60 degrees Fahrenheit
Assumed Atmospheric Pressure	14.23 PSI
Pressure Base	14.52 PSI

Supercompressibility will be used when gas is metered at pressures of 35 PSIG or greater.

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WEST VIRGINIA

W. Va.-Am. Water Co., Case No. 11-0740-W-GI, PUBLIC SERVICE COMMISSION OF WEST VIRGINIA, Commission Order (Oct. 13, 2011).

**PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON**

At a session of the PUBLIC SERVICE COMMISSION OF WEST VIRGINIA, in the City of Charleston, on the 13th day of October 2011.

CASE NO. 11-0740-W-GI

WEST VIRGINIA-AMERICAN WATER COMPANY,
a public utility, Charleston, Kanawha County.
General investigation regarding recent staffing changes.

COMMISSION ORDER

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COMMISSION ORDER

The Commission (i) dissolves the May 31, 2011 Interim Relief Order enjoining West Virginia-American Water Company (WVAWC) from reducing staff levels involuntarily except for the three categories of employees as described below, (ii) directs WVAWC to maintain capital spending at a level that will demonstrate substantial progress toward reducing its distribution infrastructure replacement cycle, (iii) directs WVAWC to collect certain statistical information to report on a quarterly basis and (iv) rules on a pending request for protective treatment.

I. INTRODUCTION

This is an unfortunate case - unfortunate in the sense that WVAWC, generally conceded to be the flagship water utility in this State, has become a victim of its own "success." That success is reflected in the thousands of residential customers added by WVAWC over the last fifteen to twenty years, tremendous growth of plant and equipment that WVAWC has installed over the last fifteen to twenty years when it undertook extensive improvement and capital expansion projects through the construction of regional treatment plants, transmission and distribution pipeline projects or public/private partnerships designed to expand its operations. It was anticipated that the cost of system improvements and expansion would be offset by increases in customer base and growth in sales.

As we mentioned in the most recent WVAWC rate case, however, the plan to offset increased costs by spreading fixed costs over a larger customer base and larger sales volumes has not fully come to fruition. The rate base of WVAWC has increased from approximately $116 million to $427 million over the past twenty years. Over the same period, the number of customers has grown by approximately 40,000, although this growth in the number of residential customers has been offset by a decline in average usage per residential customer and the loss of significant commercial and industrial sales so that the total volume of water delivered has remained relatively flat. West Virginia-American Water Company, Case No. 10-0920-W-42T (Commission Order, April 18, 2011) at 5 (2010 Rate Case or 2010 Rate Order as appropriate). The business plan that WVAWC pursued over the past twenty years has been exemplary and successful in extending service to unserved and underserved areas of the State, but the impact on rates has been affected by flat water volumes sold that tends to magnify the average increased cost per thousand gallons sold. Although WVAWC presented testimony in its rate cases that it has attempted to control costs where possible, the increased rate requirement flowing from capital investment that is not accompanied by comparable growth in sales volumes, and the impact of increasing payroll and employee benefit costs on both WVAWC and American Water Works Service Corporation costs, which likewise must be spread over relatively stagnant water sales, have overwhelmed those cost controls, angered many of its ratepayers, and brought it increasingly before this Commission to seek rate relief on a scale and frequency that most other regulated water utilities do not experience.

The customer growth that WVAWC has achieved resulted primarily from the acquisition of other water systems, many of which were troubled and required extensive upgrades and renovations. In some cases, the cost of the rehabilitation of an acquired system was coupled with upgrades and expansion of water supply, treatment, pumping and transmission facilities necessary to serve existing customers. The hope was that achieved synergies between acquired systems and existing customers would produce lower average costs per customer than could have been achieved by simply upgrading and expanding the facilities needed to service existing customers. There have been successes, and the State is fortunate to have the service capacity of WVAWC in many areas. The expansion success, however, has not been significant enough, or frequent enough, to offset the substantial additional cost to the customers as WVAWC continued to make large capital plant additions, experience increasing employee and employee benefit costs and experience stagnant water sales in spite of significant growth in the number of residential customers served.

WVAWC asserts that it has done everything that it can to lower costs and that it is the tough and unreasonable regulatory treatment that is to blame for its lack of acceptable performance in the eyes of its shareholder, American Water Works Company, Inc. (AWWC). WVAWC witnesses have asserted that they have done everything that they can in belt tightening and that the only thing left to do is to reduce its work force by thirty-one employees and to let "no appreciable reduction" in service quality become its new standard of service.

The Commission acknowledges that it has indicated in the two past general rate case orders a desire for WVAWC to seek efficiencies and cost savings where possible because of the current economic climate and recent recession. WVAWC claims that the only options left were to terminate thirty-one employees and curtail badly needed investment for replacement of distribution system infrastructure and extensions of service. Nowhere in WVAWC's information supplied in this proceeding did it mention other options such as curtailing pay raises for its employees, reducing employee incentive or bonus compensation plans, considering incremental tweaks in work days spread over the entire workforce, or any other of a number of options we see other private sector companies, other utilities and government agencies pursuing over the last few years. WVAWC should continue to seek efficiencies and cost saving measures where possible, but not in a way that significantly increases the risks of inadequate service and curtails capital investment essential to maintaining adequate service and meeting its obligation to serve new customers.

WVAWC also argued that it is the policies and ratemaking treatments of the Commission that have placed it in its current predicament and that the Commission should refrain from second-guessing the actions of WVAWC management in laying off employees or adopting an "undertake no marginal investment" philosophy, asserting that this Commission is not a "super Board of Directors" of WVAWC and should not interfere with that new philosophy. We agree that we are not a "super Board of Directors." By the same token, we have a statutory obligation to review and oversee the actions and activities of WVAWC as it relates to customer service. To paraphrase a famous line, the Commission is "[n]ot a potted plant. . . . That [oversight] is . . . [our] job."[1]

After review of the pre-filed testimony and two days of hearing, the Commission has decided that it must, consistent with its statutory obligations, review the justifications WVAWC put forward for the thirty-one terminations and determine if those terminations will, in our opinion, have an adverse impact on service or the operations of WVAWC. In most instances, the Commission defers to the reasonable justifications WVAWC offered. As related to three areas of employee activity discussed below, however, the Commission has concluded that WVAWC has not put forward a rational basis for its actions. Instead, the proposed layoffs related to the valve program, Webster Springs operations and certain field employees that may perform meter reading, shutoff, and other distribution plant work (ten out of the thirty-one terminations) constitute an unreasonable practice and will cause an increased risk of degradation in service that has not been justified by WVAWC. The Commission takes this opportunity to state that the actions of the Commission in this proceeding are not routine; instead, the Commission takes these steps only because this situation requires an extraordinary remedy. The Commission has no intention of becoming, and will not become, an appellate authority for adjudications of disputes regarding day-to-day, ordinary management or staffing decisions of any utility.

II. BACKGROUND

A. Procedural History

On May 25, 2011, the Utility Workers Union of America, AFL-CIO, and UWUA Local 537 (UWUA) filed a formal complaint alleging that WVAWC improperly reduced its staff by thirty-one employees, thereby jeopardizing the ability of WVAWC to provide safe and adequate water service to its customers. The UWUA asserted that the reduced headcount is insufficient to run existing water operations in a proper and reasonable manner and requested that the Commission (i) open a general investigation into the matter, (ii) direct WVAWC to file documents justifying its staffing reduction and (iii) stay the planned layoffs pending further investigation. In support of its complaint, the UWUA filed an affidavit from Gregory Lanham attesting to the facts it asserted.

The Commission subsequently directed WVAWC to file an answer within ten days. May 25, 2011 Commission Order.

On May 27, 2011, the UWUA filed a revised certificate of service for its complaint.

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[1] Iran Contra hearings; Response of B. Sullivan, Esq., to Senator Daniel Inouye (1987).

The Commission issued an Order on May 31, 2011, directing WVAWC to produce and file documents supporting its recent staffing reductions and provide the Commission with a description of each position eliminated. The Commission also enjoined WVAWC from reducing staffing levels through involuntary termination unless the employees had already been terminated.

On June 1, 2011, WVAWC filed a partial response to the May 31, 2011 Commission Order. WVAWC indicated that it was prepared to supply the requested information for Commission review. WVAWC also stated that it was not obligated to return the affected employees because they were no longer working.

On June 2, 2011, the UWUA filed a letter responding in opposition to the June 1, 2011 WVAWC letter.

Also on June 2, 2011, the Commission's Consumer Advocate Division (CAD) petitioned to intervene arguing that this matter may have an impact on ratepayers.

Separately, the Laborers International Union of North America, Local 1353, AFL-CIO (LIUNA) petitioned to intervene to advocate for the interests of its membership.

The Commission subsequently restated the directive in the May 31, 2011 Commission Order. June 2, 2011 Commission Order.

On June 6, 2011, WVAWC filed an answer denying any wrongdoing and requested that the Commission dismiss the complaint, arguing that the UWUA is using this proceeding to entangle the Commission in a pending labor contract negotiation. WVAWC also submitted documents responding to the May 31, 2011 Commission Order.

The Commission converted this proceeding to a limited general investigation into the staff reductions, its basis, including changes in capital and maintenance spending, and the likely effect on service quality, granted pending requests to intervene and established a procedural schedule. The procedural schedule included deadlines for filing of direct and rebuttal testimony. June 9, 2011 Commission Order.

On June 13, 2011, WVAWC requested that the Commission modify the deadline for the filing of rebuttal testimony. The Commission adjusted the filing deadline as requested. June 15, 2011 Commission Order.

On June 16, 2011, the UWUA requested the *pro hac vice* admission of Scott Strauss, Esq., and Katherine Mapes, Esq. The Commission granted the motion. June 16, 2011 Commission Order.

On June 29, 2011, Staff filed an initial memorandum stating that it would continue to investigate this matter and follow the procedural schedule the Commission previously established.

Also on June 29, 2011, WVAWC filed direct testimony in support of the staffing reductions.

On July 11, 2011, Staff, CAD and the UWUA filed their direct testimony.

On July 18, 2011, WVAWC and UWUA filed rebuttal testimony.

On July 20, 2011, WVAWC objected to portions of the UWUA rebuttal testimony.

On July 21, 2011, the parties filed a document listing the order of presentation of evidence agreed among the parties. Separately, UWUA requested that the Commission admit portions of the evidentiary record from the 2010 Rate Case into the evidentiary record for this proceeding.

The Commission called this matter for hearing on July 26, 2011.[2] At hearing, the Commission requested that the parties address the applicability, if any, of stipulations from West Virginia-American Water Company et al., Case No. 01-1691-W-PC (Commission Order, October 23, 2002). It took administrative notice of the documents listed in the July 21, 2011 request from the UWUA, allowing consideration of those portions of the evidentiary record from the 2010 Rate Case. The Commission also overruled the objection WVAWC filed relating to the UWUA rebuttal testimony.

After accepting testimony and exhibits from the parties, the Commission denied a request from WVAWC to summarily dissolve its May 31, 2011 Interim Relief Order and established a briefing schedule.

On July 29, 2011, WVAWC requested a protective order covering several documents it filed in this proceeding. LIUNA joined in the request to the extent that it involved employee wage and benefit data.

On August 24, 2011, LIUNA filed an initial brief advocating for the Commission to continue to prohibit WVAWC from making its planned staff reductions.

On August 25, 2011, UWUA filed an initial brief requesting that the Commission (i) continue its order forbidding involuntary staff reductions through the next rate proceeding and (ii) direct WVAWC to revert to its initial 2011 capital spending budget.

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[2] The Commission will refer to testimony from the transcript of the July 26, 2011, proceedings as Tr. I, and will refer to the July 27, 2011 hearing transcript at Tr. II.

Separately, WVAWC filed an initial brief requesting that the Commission dismiss this proceeding and dissolve its May 31, 2011 Commission Order. CAD and Staff each filed briefs expressing concern with the staffing reductions WVAWC planned, but advocating for a monitoring program to detect any possible future service quality erosion.

On September 8, 2011, Staff filed a letter informing the Commission that it would not file a reply brief. CAD, WVAWC and UWUA filed reply briefs responding to initial briefs.

Also on September 8, 2011, the Regional Development Authority of Charleston-Kanawha County, West Virginia Metropolitan Region, Lewis County Economic Development Authority, Oakvale Road Public Service District and the Lashmeet Public Service District (Partnership Intervenors) petitioned to intervene in this matter. Each entity has a relationship with WVAWC in the form of public/private partnership and ongoing Operation and Maintenance Agreements to provide water service. The Partnership Intervenors stated that WVAWC recently withdrew from a series of proposed projects, including projects with each entity. The Partnership Intervenors believe that they have an interest in this matter. They also sought a new round of briefing to put forward further factual and legal matters.

On September 9, 2011, LIUNA filed a reply brief.

On September 12, 2011, UWUA filed a response in support of the intervention request from the Partnership Intervenors and expedited further briefing. WVAWC separately opposed the intervention request.

The Commission denied the request to intervene from the Partnership Intervenors and indicated that they should file a separate complaint if they desire to pursue the matter further. The Commission also elected to consider the impact of the conditions imposed in Case No. 01-1691-W-PC (Commission Order, October 23, 2002), if any, in that subsequent matter. September 21, 2011 Commission Order.

B. Underlying Circumstances

This proceeding opened on May 25, 2011, with the complaint filed by the UWUA requesting that the Commission prohibit WVAWC from completing a substantial reduction in the number of employees (thirty-one terminations, or about ten percent of the WVAWC workforce). UWUA asserted that the planned terminations would substantially impair the ability of WVAWC to provide reliable safe water to its customers. The workforce reduction also stood in stark contrast to testimony WVAWC filed in its recent rate proceeding asserting that, after careful review, WVAWC required 316 employees instead of the approximately 279 employees that would exist after the proposed terminations. 2010 Rate Case Ex. WDM-R at 5.

In response to the allegations, the Commission granted interim relief on May 31, 2011, to stay the terminations pending a review of this matter.

On April 18, 2011, the Commission issued its final Order in the 2010 Rate Case. In the 2010 Rate Order, the Commission granted WVAWC $5.13 million out of its initial $18.4 million rate increase request. The Commission also determined that WVAWC had a total rate base of $427.3 million and because of WVAWC's specific circumstances granted WVAWC a special accounting and ratemaking treatment for accumulation of an Allowance for Funds after Construction (AFFAC). AFFAC allows WVAWC to earn a return on capital investment in distribution system replacements between general rate cases. At present, no other utility operating in West Virginia has been authorized to use AFFAC. That Order also rejected a request from the UWUA to scrutinize staffing levels or require that the allocations from the revenue requirement calculation be spent as calculated. 2010 Rate Order at 21, 66.

WVAWC has repeatedly pointed to its inability to earn its authorized rate of return and adverse rulings in the 2010 Rate Order as part of the justification underlying its actions at issue here. The Commission refuses to relitigate the 2010 Rate Case in this proceeding, but will briefly touch on that matter before analyzing the other justifications WVAWC has advanced for the staff terminations. WVAWC is always free to request a rate increase based on a new historical test year, adjusted for going-level changes in costs, if it believes that it is entitled to higher rates.

WVAWC obtained a portion of the rate relief it sought in the 2010 Rate Case, but other parties in that proceeding presented starkly contrasting estimates of the rates to which WVAWC was entitled.[3] In fact, Staff argued to the Commission in that case that the WVAWC then current rates were $1.025 million too high. 2010 Rate Case Ex. DLK-D at 3. CAD calculated that WVAWC was entitled to a rate increase of only $1.68 million factoring in a return on common equity of ten percent. 2010 Rate Case Ex. RCS-1, Revised Schedule A-1. The Commission subsequently ruled that WVAWC was entitled to an equity return comparable to what litigated cases in both Kentucky and Ohio recently had awarded. <u>See</u>, 2010 Rate Case Ex. MAM-R at MAM-16, <u>Kentucky-American Water Company</u>, Case No. 10-00036 Order of December 14, 2010 (Kentucky PSC). The Commission also notes that it agreed with WVAWC on many components of the revenue requirement calculations, including the proper number of employees to include for payroll expense, including funds for temporary employees to perform collections, rejecting a vacancy rate that CAD recommended and normalizing the effect of a new tax deduction that accelerated the tax deduction of certain expenditures that were capitalized for book purposes but could be expensed for tax purposes. 2010 Rate Order at 62, 64. The 2010 Rate Order also partially accepted the WVAWC requests on several other cost components including a portion of the adjustment for pension costs, a

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[3] Records of this Commission indicate that over the past twenty years, WVAWC has filed a dozen rate cases and received approval for more than $50 million in additional revenues in those cases.

portion of incentive plan costs, the tax expense calculation WVAWC utilized[4] and in particular granting the AFFAC treatment to allow WVAWC to earn a return on certain plant investments between rate cases. Id. at 64-66.

WVAWC obviously disagrees with the Commission on the correctness of the various rulings that underlie the rate increase awarded in the 2010 Rate Order, but the Commission continues to believe that award, overall, was fair and reasonable. Thus, the Commission views the current case as turning on the decision to terminate thirty-one employees of WVAWC, instead of viewing this case as an extension of the 2010 Rate Case. The timing of the terminations, within days of the 2010 Rate Order becoming final and non-appealable, may raise a question about the motivations of WVAWC; however, as set forth below, the reasonableness of its practices in light of the obligation to maintain quality water service is the focus of the Commission inquiry and ruling in this proceeding.

C. Public Service Obligations and the Standard for Review

This proceeding raises the question of the degree of supervision that the Commission can and should exercise over the decisions of utility management. Under Chapter 24 of the West Virginia Code, the Commission is charged with ensuring that utilities in this State provide adequate, economical and reliable utility service that is based primarily on the cost of providing the service. This Commission has not only the statutory authority, but also the statutory obligation, to undertake the examination that has been made in this case. The Commission evaluates the actions and plans of WVAWC under a host of regulatory responsibilities. For instance, under the provisions of W.Va. Code §24-1-1, the Commission is charged with the duty to enforce and regulate the practices, services and rates of public utilities:

> (a) It is the purpose and policy of the Legislature in enacting this chapter to confer upon the Public Service Commission of this State the authority and duty to enforce and regulate the practices, services and rates of public utilities in order to:
>
> > (1) Ensure fair and prompt regulation . . . in the interest of the using and consuming public;
> >
> > (2) Provide the availability of adequate, economical and reliable utility services throughout the State;
>
> . . . .

[4] WVAWC requested an effective consolidated federal income tax rate of 19.7 percent, while continuing to argue that the Commission should assume that it pays at the full statutory tax rates based on its payments to the affiliated consolidated tax group.

> (b) The public service commission is charged with the responsibility for appraising and balancing the interests of current and future utility service customers, the general interests of the state's economy and the interests of the utilities subject to its jurisdiction in its deliberations and decisions.

W.Va. Code §24-1-1(a) and (b).

The Commission also has, under W.Va. Code §24-2-2, the "power to investigate all rates, methods and practices of public utilities . . . [and] to require them to conform to the laws of the State and to all rules, regulations and orders of the commission not contrary to law. . . ."

Likewise, the Commission has broad explicit powers under subsection (a) of W.Va. Code §24-2-7:

> (a) Whenever, under the provisions of this chapter, the commission shall find any regulations, measurements, practices, acts or service to be unjust, unreasonable, insufficient or unjustly discriminatory, or otherwise in violation of any provisions of this chapter, or shall find that any service is inadequate, or that any service which is demanded cannot be reasonably obtained, the commission shall determine and declare, and by order fix reasonable measurement, regulations, acts, practices or services, to be furnished, imposed, observed and followed in the state in lieu of those found to be unjust, unreasonable, insufficient, or unjustly discriminatory, inadequate or otherwise in violation of this chapter, and shall make such other order respecting the same as shall be just and reasonable.

Based on the statutory authority quoted above, this Commission may look at the acts and practices of any utility under its jurisdiction, including WVAWC, and determine whether the acts and practices of a utility or the services provided by the utility are unreasonable or insufficient. If the Commission so finds, the Commission may "fix" or establish reasonable practices and sufficient service. This is not acting outside of its jurisdiction or acting as a "super board of directors," it is instead complying with the statutory mandate and authority of the Commission as part of its supervision of public utilities. A public utility accepts that supervision as a part of its public service obligation in exchange for its operating authority, including a monopoly franchise for providing its service within the State. To state the obvious, the acts, practices and service of a utility are generally the result of management decisions.

Although the Commission has the statutory authority to regulate both utility rates and practices, the Commission does not supplant the judgment of utility management without cause. The Commission has stated that utility management is charged with making day-to-day decisions in its operations and with setting the long-term policies, practices and plans of the utility as long as they do not violate our rules or the provisions of the West Virginia Code.[5] 2010 Rate Order at 10. That general proposition, however, is tempered in situations where the actions of a utility may, among other things, affect its ability to provide service. For example, this Commission would not allow a utility to cease operations without permission. W.Va. Code §24-3-7. The Commission does not leave it to the utility to determine if it should impose a moratorium and refuse service to new customers because of inadequate facilities. The Commission also stepped forward to investigate a decline in the quality of landline telephone service provided by the former Verizon West Virginia. Verizon West Virginia Inc., Case No. 08-0761-T-GI (Commission Order, June 30, 2008).

In this case, the Commission was concerned that a termination of approximately ten percent of WVAWC's employees directly contradicted recent testimony from the utility in the 2010 Rate Case and warranted further scrutiny. The Commission opened a general investigation focused on the factual support for those terminations and the likely effect on service quality. The Commission also recognized the link between WVAWC capital budgets with its staffing needs and considered that linkage where relevant to the staff reduction and service quality issues.

III. EVIDENCE IN THE PROCEEDING

Four parties presented testimony in this matter, including testimony from WVAWC defending the planned staffing reductions, testimony from the UWUA opposing the terminations and testimony from Staff and CAD recommending that the Commission permit the terminations conditioned on WVAWC collecting statistical information to allow monitoring of its service quality. The Commission will discuss the proposed monitoring mechanisms in detail in Section H below.

A. WVAWC Testimony

In response to the May 31, 2011 Commission Order, WVAWC filed exhibits with its answer outlining its staffing reductions. Under what WVAWC termed its "Get Well Plan," WVAWC eliminated a total of forty-six positions. Considering already vacant positions that were to be eliminated and transferring several employees among functional positions, WVAWC planned to reduce its total number of employees by thirty-seven to 279 employees and to terminate a net thirty-one employees. It filed descriptions of each position included in its staffing reductions as directed. WVAWC Answer.

On June 29, 2011, WVAWC filed direct testimony in support of its layoffs. The WVAWC president, Mr. Morgan, described his justification for the various classes of staff terminations except for field service and water quality employees. In the engineering department, WVAWC eliminated two engineers, a draftsman and the senior

[5] The Commission also addressed the argument WVAWC raised that examining the staffing reductions was tantamount to acting as a super board of directors when rejecting a Motion to Dismiss in the June 9, 2011 Commission Order.

secretary, leaving three engineers and a draftsman. Mr. Morgan explained that WVAWC would not require the eliminated positions because of a lack of capital for discretionary infrastructure investment. Similarly, WVAWC concluded it did not need a business development specialist, and it would leave any work in that area to its business development manager. WVAWC also eliminated its finance manager position and planned to obtain those services from an affiliate. WVAWC elected to eliminate two of seven operations support positions after reorganizing the department. It also sought to obtain some of the services formerly provided by the terminated employees from its affiliated service company. Ex. WDM-D at 7-9.

WVAWC planned to reduce the number of supervisors in its operating districts, including the elimination of one of three supervisors in its Northern Division, one of four supervisors in its Huntington District, two of five field service supervisors in the Kanawha Valley District and one of two supervisors in the Southern Division by sharing one supervisor between two treatment plants in that Division. Finally, WVAWC planned to reduce the number of supervisors at its New River Treatment plant from two to one. Id. at 9-14. In each case, Mr. Morgan asserted that WVAWC would be able to operate without the eliminated positions because supervisors will have reduced workloads because of reduced capital spending. Id. at 13. He also asserted that day-to-day customer service would not be materially diminished because the AWWC call center has not been altered by the staffing reductions, and technology allows fewer meter routes. Id. at 16. WVAWC may, however, experience increased line breaks and increased response times. Id. Mr. Morgan also put forward his opinion that the staffing reductions were dictated by the recent 2010 Rate Order and the prolonged history of WVAWC failing to achieve its authorized rate of return. Id. at 18-22.

WVAWC filed testimony from its chief operating officer, Mr. Amos, in support of its reductions to non-exempt hourly positions. He divided the staff reductions in his area of responsibility by district or division. In the Northern Division, Mr. Amos testified that the reduction of one position in Webster Springs would not adversely affect operations and noted that employees from neighboring WVAWC facilities in Gassaway or Weston could assist Webster Springs as needed. Ex. DRA-D at 4. WVAWC planned to eliminate one utility worker of thirty-seven total employees from its Southern Division based on the expected reduction in capital spending. Id. at 5. Additionally, WVAWC planned to eliminate one of twelve employees at its Salt Rock District. WVAWC believes that it can operate the Salt Rock facilities without that employee. Id. at 6. In the Huntington District, WVAWC determined that it could operate without four distribution employees. Two of these eliminated positions came from the elimination of the separate valve program for this area. Mr. Amos ascribed the other two layoffs to reduced capital spending. He asserted that the remaining nineteen employees could assume the duties of the four eliminated positions. Id. at 7. In addition to the distribution employees, WVAWC determined that it needed three fewer meter reader/field service positions in the

Huntington District.[6] WVAWC has adjusted its meter routes, plans to add additional radio read meters and will adjust collection activities eliminating the need for the three meter reader/field service representative positions. Id. at 8, 9. It also eliminated one administrative assistant in Huntington based on the reduced number of supervisors in the Huntington District. Id. at 9.

In the Kanawha Valley District, WVAWC slated four of the current forty-five distribution employees for layoffs, three of whom comprise the local valve program crew. It also plans to move six positions from field service to construction and plans to eliminate two meter readers. WVAWC justified the reduced number of meter readers by the installation of 12,111 radio read meters and a reduction in meter routes from 243 to 219. In consideration of the outsourcing of most vehicle and equipment maintenance, WVAWC also planned to eliminate an assistant mechanic position. Id. at 9-11. It determined that reduced capital spending would allow for the elimination of one utility worker and a vacant supervisor position in its Boone County operations. Five employees will remain in that area. Finally, WVAWC plans to eliminate one of twelve employees in its Oak Hill operations. It recently replaced all the meters in the Oak Hill District with advanced metering infrastructure that does not require meter readers in the field. Id. at 11-13.

WVAWC also presented testimony from Billie Suder, the WVAWC Manager for Water Quality and Environmental Compliance. Ms. Suder testified that the planned staffing reduction would not interfere with WVAWC water quality. Under the planned staff reductions, two supervisors will divide their time between water quality services and other responsibilities, and one position will be eliminated. Ex. BJS-D at 4, 5. Ms. Suder assured the Commission that the employees dividing their time will be able to perform both functions. According to Ms. Suder, one supervisor will also act as an operator at an automated plant, and the divided responsibilities of the second employee are merely a reflection of an existing arrangement. Id. at 6. Thus, she concluded that the quality of WVAWC water will not be impaired by the elimination of one water quality technician.

On rebuttal, WVAWC disputed testimony from the UWUA regarding the potential risks from the staffing reductions it seeks to implement and other assertions from opposing parties. It discounted the gravity of incidents UWUA witnesses, Ms. Bonnette and Mr. Lanham, cited in their direct testimony. Ex. DRA-R at 3, 6, 7. WVAWC agreed with the proposals to implement a service quality monitoring program and offered comments regarding the CAD and Staff proposals. Ex. WDM-R at 1. It agreed that reduced line replacement spending is counterproductive, but attributed that result to the Commission decision to deny its request for a distribution system improvement charge in the 2010 Rate Order. Id. at 2, 3. It acknowledged that the layoffs necessarily require its remaining employees to do more with less. Id. at 4. WVAWC objected to any

[6] The number of meter readers expected to be terminated varies from the number of positions eliminated because of the seniority of the various workers involved as specified by the prevailing collective bargaining agreement. Ex. DRA-D at 7.

implication that it misled the Commission relating to its reallocation of capital spending. Id. at 11-14. WVAWC also expressed concern about using information from a monitoring program to assure that there would be no reduction in service quality. It clarified that it never meant to pledge or imply that there would be no reduction in service quality and attempted to distinguish between its current level of customer service and existing relevant statutory or regulatory requirements. The rebuttal stated that WVAWC had not made any pledge that there would be no reduction in service quality. WVAWC stated that its only assurance was that it would meet the relevant requirements for service quality. Id. at 8, 10.

Finally, WVAWC attributed an increase in boil water advisories to a recent regulatory change in advisory requirements and asserted that it will continue to have sufficient staff to handle boil water advisory notices as needed.[7] Ex. BJS-R at 2-5.

B. UWUA Testimony

UWUA presented testimony from two witnesses employed in the Huntington District. Gregory Lanham is an Equipment Operator and Kim Bonnette is a Field Service Representative. Each began working at WVAWC in 1984. Ex. GL-D at 1, KB-D at 1. Mr. Lanham previously filed testimony in the 2010 Rate Case. Ex. GL-D at 3. Consistent with his testimony in the 2010 Rate Case, Mr. Lanham predicted that WVAWC would be unable to perform properly preventative maintenance, which, in turn would result in reduced service quality and reliability. He repeated his opinion that WVAWC is thinly staffed even before consideration of the proposed reductions subject to this proceeding. Id. at 3, 4. Over the last decade, the level of union employees in the Huntington District has decreased from fifty-four to forty-four employees without a substantial change in workload. Id. at 5.

Mr. Lanham argued that a further reduction in capital spending is not sustainable based on his observations. He believes that the layoffs described in WVAWC direct testimony are not involved in capital projects. He noted that in the Huntington District, line replacements over 500 feet in length are already performed by contractors instead of WVAWC personnel. Id. at 10, 11. He believes that delaying line replacement spending will result in increased costs, describing the WVAWC plans as a "band aid" approach. Id. He predicts similar problems for other infrastructure, including pumps, because of a lack of maintenance mechanics. Id. at 18, 19. Mr. Lanham also argued that reducing a position at the Webster Springs plant would impair service if a line break forces an operator to suspend plant operations there while making repairs. Id. at 12-13.

[7] The Commission notes with concern frequent WVAWC announcements regarding an increased number and increased severity of leaks resulting in boil water advisories, particularly in Huntington and Charleston. Whatever the regulatory requirement for advisories, the fact is that the announcements are due to line breaks or significant pressure reducing leaks and that several of these recent leaks have been on large mains within the urban areas.

In regard to the Huntington District, Mr. Lanham concluded that WVAWC will not be able to provide the current level of service with fewer employees. He believes that the immediate impacts will include increased line breaks and reduced responsiveness to problems that have a direct and current impact on customer service. Id. at 13. He pointed to two recent examples of WVAWC delaying line repairs until a repair crew was available. Id. at 14, 15. Thus, he predicts that customers will be without water with increasing frequency and duration, and that continuing leaks will potentially lead to property damage. Id. at 16.

Mr. Lanham also reiterated his concern for valve maintenance in the Huntington District. In his 2010 Rate Case testimony, Mr. Lanham argued in favor of continued valve maintenance as a means of isolating leaks and reducing property damage. See, 2010 Rate Order at 9, 2010 Rate Case Ex. GL-D at 15, 16. He asserted that WVAWC has knowledge of broken valves in the Huntington area. Ex. GL-D at 22. He noted that the precise locations of valves are periodically lost because of construction that is unrelated to water line replacement causing repair delays. Id. at 23. Restricting valve maintenance to valves over sixteen inches in size is not an effective program to prevent customer impacts. Id. at 23, 24. Finally, Mr. Lanham noted a recent increase in boil water advisories and argued that the proposed staff reductions would prevent WVAWC from distributing direct notices placed on affected customers' doors of those advisories. Id. at 25, 26.

UWUA also filed testimony from Kim Bonnette, a field service representative employed by WVAWC in the Huntington District. Ex. KB-D at 1. In her position, she addresses customer service complaints, turns water service on or off and investigates leaks. Id. She testified that WVAWC eliminated two field service employees who act as fill-ins for other field service employees with assigned territories. Id. at 3. Without these additional employees during the two-week period the layoffs were in force, she testified that WVAWC had insufficient employees to address potential emergencies on at least two occasions. Id. at 3-5. Ms. Bonnette also noted that WVAWC eliminated a senior secretary in her area, thereby hampering the ability of other employees to perform their normal jobs. Id. at 6. Another result of the layoffs, according to Ms. Bonnette, was increased overtime for work that previously occurred during normal business hours. Id. at 6, 7. Finally, Ms. Bonnette cast doubt on the effectiveness of radio read meters, asserting that radio read meters are a small portion of the total meters in her district, but require a disproportionate number of second readings to accurately determine customer usage. Id. at 8.

In rebuttal testimony, Ms. Bonnette asserted that the two-week period when the proposed layoffs were in force caused a substantial backlog in customer service requests. Service request delays expanded from between one to two days up to fourteen days. Ex. KB-R at 1, 2.

C. Staff and CAD Recommendations

Staff and CAD each filed testimony recommending that the Commission monitor WVAWC service quality, but allow WVAWC to proceed with the proposed layoffs. Ex. IF-D at 9, 10, Ex. BLH-D at 4. Staff expressed concern with WVAWC capital spending plans. Ex. IF-D at 7, 8. CAD noted that WVAWC has not reduced its capital investment budget, but instead has redirected a portion of capital spending from plant expenses to participate in a program to invest in information technology. Ex. BLH-D at 7. This project will replace existing accounting and customer service software. Tr. I at 72, 73. Staff and CAD each proposed that the Commission direct WVAWC to implement a monitoring program as described below. The monitoring programs are designed to alert the Commission to a decrease in customer service quality, allowing remedial measures. Ex. IF-D at 9, 10, Ex. BLH-D at 4, 9.

IV. DISCUSSION

A. In General

The disagreement over the proposed thirty-one terminations in this case highlights the balancing required of any utility between adequately providing for system operations and maintenance while simultaneously providing utility service at the lowest reasonable cost. In recent rate proceedings, this Commission has repeatedly urged WVAWC to monitor costs and to control expenses. WVAWC, Case No. 08-0900-W-42T (Commission Order, March 25, 2009), 2010 Rate Order at 1. The Commission continues to stand by those admonitions here and fully supports WVAWC efforts at cost containment, provided that the results do not yield an unreasonable risk to utility facilities, property, public safety or service quality.

Some of the testimony in this matter includes a degree of reasonable expectation on the future adverse results of the proposed terminations. When these expectations are based on reliable testimony and evidence, we will not wait for actual service problems to support a finding that the actions of WVAWC are unreasonable. The requirement for evidence of unreasonable acts or practices can be based on reasonable expectations and does not require the Commission to wait until the facilities of a utility are so poor that consumer complaints increase to unprecedented levels or result in instances of dangerous conditions or inadequate service.

B. Strength of WVAWC Justifications

Although the Commission did not concur with some of the expenses WVAWC proposed to consider in ratemaking during the 2010 Rate Case, it did include funds for 316 employees in its revenue requirement calculation and expenses for temporary employees related to pursuing unpaid accounts. 2010 Rate Order at 64. Within days of that 2010 Rate Order being final and nonappealable, however, WVAWC announced its plans for the terminations that are the subject of this case, terminations that UWUA and

LIUNA contend are beyond the level that would allow WVAWC to properly maintain its current operations. These reductions have been characterized by some parties as retaliation or punishment by WVAWC or AWWC management against this Commission or the public in general. See, Complaint at 3, 4. The Commission is hesitant to believe that WVAWC or AWWC management made these substantial decisions on how it intends to operate its business out of the equivalent of corporate "spite." Instead, the Commission views and tests these layoffs in the light of WVAWC's utility obligation to provide adequate and reliable service, and the Commission's statutory obligation to assure that takes place.

WVAWC has provided data in support of its layoff decisions with both the documents attached to its answer on June 6, 2011, and its direct testimony filed on June 29, 2011. It rebutted many of the arguments of other parties in subsequent testimony. The exhibit attached to the WVAWC answer noted that it eliminated full-time positions that resulted in a net of thirty-one terminations after taking into account existing vacancies and various employee reshuffling. The UWUA and to a degree both Staff and CAD argue that WVAWC failed to conduct any analysis to support the layoffs. The Commission, however, concludes that in most cases, WVAWC has put forward an adequate and credible justification for its layoffs in the testimony described above. Although other parties or this Commission may disagree with the methodology WVAWC employed and the nature of some of its assertions, WVAWC has put forward an analysis of its current staffing in each operating area and how it arrived at its layoffs.

In instances where WVAWC has unreasonably reduced employment levels to the point that it presents an inefficiency, expected degradation of service below acceptable levels or an unacceptable risk of damage to property, the Commission will direct WVAWC to reconsider and reverse those practices. The Commission concludes that three of the staffing decisions are unreasonable practices as detailed below. Otherwise, the Commission cannot conclude that the planned layoffs are unreasonable and, with the exceptions discussed below, the Commission will dissolve the interim relief it previously granted and allow WVAWC to carry out the workforce terminations it deems necessary to provide reliable service at reasonable costs.

C. Valve Program

The first area of substantial Commission concern with the proposed WVAWC layoffs is the elimination of the existing systematic and scheduled valve location, testing and maintenance program (valve program). WVAWC has maintained a valve program in one form or another for many years. The cost of that program is included within the current revenue requirement of WVAWC. Valves allow WVAWC employees to isolate a water leak or line break for repair. In an emergency situation, properly operating valves prevent the depletion of potable water held in storage tanks. Ex. GL-D at 20, 21. As demonstrated by the recent line break in the Edgewood area of Charleston, operating valves prevent a line break from affecting larger areas. Tr. I at 140-144, 146-148. In the past, AWWC established targets for locating and exercising (physically operating the valves to determine that controls are working as required) system valves. 2010 Rate Case Ex. GL-D at 17, 18. As noted by Mr. Lanham, without a regular valve program, the exact location of existing valves becomes lost or valves become inaccessible because of paving or other construction activities. Ex. GL-D at 23.

In this proceeding, the parties agree that a likely result of the proposed layoffs and the associated reduction in capital spending on distribution system infrastructure replacement is some increase in the frequency of main and service line breaks and leaks. The degree of change and the impact on customers is disputed, but increases in main and service line breaks and leaks are likely. That level, however, is also affected by a number of other factors that vary over time. Ex. WDM-R at 10. Despite the possibility for increased main and service line breaks and leaks, WVAWC plans to scale back its systematic and scheduled valve program in the Huntington and Kanawha Valley Districts. In the Kanawha Valley District, WVAWC currently has a three-employee crew dedicated to the valve program. The Huntington District has a dedicated two-employee valve program crew. WVAWC planned to eliminate both crews as part of its staffing reductions. Ex. DRA-D at 7, 10. WVAWC stated that it will continue to focus on large valves on lines over thirty-six inches in diameter, but will not continue ongoing, systematic scheduling of dedicated valve activity this year for valves less than thirty-six inches. Thirty-six-inch lines constitute a relatively small portion of system valves and exist only in Kanawha Valley and Huntington. Tr. I at 143-145, 259. In fact, WVAWC asserted that it has already met its targets for valve evaluation for 2011 in the Huntington District. Thus, it concluded that these employee positions are unnecessary. WVAWC indicated that it may reevaluate this decision in 2012 if needed. Id.

Testimony provided by the UWUA highlighted the need for an effective valve program to isolate and limit the damage from main and service line breaks and leaks. Operable valves allow repair crews to isolate a leak or line break for repair, thereby reducing the number of affected customers. Ex. GL-D at 20. Repairing a leak with active line pressure requires compensatory measures not needed for a repair without line pressure. Id. at 22. Further, allowing a leak to run unabated increases costs for WVAWC while possibly causing property damage near the break or posing fire suppression problems. Id.

Considering the stated intentions of WVAWC to cut costs by minimizing capital spending and the likelihood for increased main and service line breaks that may result, the Commission believes that scrapping a scheduled and systematic valve program is wrong. An alternative approach that is heavily weighted with random valve operations at the time of main breaks and emergencies is not an effective replacement for a scheduled and systematic valve location, testing and maintenance program that covers all the system valves on a regularly scheduled basis (depending on the valve size and criticality). Properly functioning valves are critical to minimizing the extent of customer service interruptions associated with main breaks and property damage that will increase with the planned staffing reductions and lowered capital spending contemplated by WVAWC. To simultaneously reduce capital spending on distribution system infrastructure without an effective valve operation and maintenance program is an unreasonable practice that the Commission will not allow. The Commission will require WVAWC to maintain the existing scheduled and systematic valve programs and to retain the five existing positions dedicated to that function in the Kanawha Valley and Huntington Districts.

D. Webster Springs Operations

The second area of Commission concern over the proposed layoffs is the lack of sufficient staffing at the Webster Springs plant. According to the testimony of UWUA witness Lanham, the layoff of an employee based in Webster Springs will create a situation where on certain days of the week, the only employee available in Webster Springs is the plant operator. If a significant line break or other emergency arises, that operator must shut down the plant before he responds. Ex. GL-D at 12, 13. WVAWC asserted that employees from neighboring WVAWC systems in either Gassaway or Weston could respond to assist the operator in Webster Springs as needed. Ex. DRA-R at 4.

The UWUA has raised a valid concern regarding the proposed layoff in Webster Springs. The plan WVAWC put forward may work under normal circumstances. In an emergency or in severe weather, the Commission believes that one employee is inadequate to operate the local water plant, perform scheduled commercial and distribution customer orders and effectively address the emergency situation. Even if the plant did not have to be shut down when a single operator was called out for some emergency, it is unreasonable to limit the number of available employees to one. The geography and terrain of the Webster Springs area and its relative isolation from WVAWC's other operations will delay the arrival of assistance from other WVAWC employees under normal circumstances, and even more so during adverse weather conditions. Thus, the layoff presents a high risk of increased cost to WVAWC, inadequate service to customers in the Webster Springs District or property damage to its customers. The Commission concludes that this staffing reduction is unreasonable and will direct WVAWC to maintain the current staffing level in its Webster Springs District, thereby eliminating one of the planned terminations.

E. Meter Readers/Field Service Representatives

The third area of Commission concern regarding the proposed terminations is the planned elimination of meter readers/field service representatives in the Kanawha Valley and Huntington Districts. Under the plan WVAWC submitted, it will eliminate two meter readers and one field service representative in its Huntington District and two meter readers from its Kanawha Valley District. WVAWC argued that introduction of radio read technology in some of its operations and a reduction in metering routes justifies the elimination of these positions. Ex. WDM-D at 16, Ex. DRA-D at 7, 8, 10, 11. In Charleston, WVAWC has reduced the number of meter routes from 243 to 219 since 2008, a fact apparently present when WVAWC argued for 316 employees in the 2010 rate case. Ex. DRA-D at 10. UWUA filed testimony, however, that WVAWC has not substantially deployed radio read meter technology in the Huntington District, with approximately nine percent of meters using that technology. Ex. KB-D at 8. Most meters instead are touch read meters. Id. The Kanawha Valley District has approximately fifteen percent radio read meters for its 82,493 customers. Ex. DRA-D at 9, 10.

Ms. Bonnette also testified about the efficiency of employing and deploying radio read meters. Despite accounting for less than ten percent of the total meters used in the Huntington District, she testified that the radio read meters account for approximately half of the requests to re-read meters in her area of responsibility. Ex. KB-D at 8, Tr. II at 77. She stated that the pattern of meter re-reads has not declined since their introduction. Tr. II at 78. For each request to re-read a radio read meter, the employee must go out and manually read that meter. Id. at 80, 81.[8] Ms. Bonnette also testified that because of union seniority all seven positions eliminated at the Huntington District worked in the commercial department and the layoffs eliminated the floater positions that were primarily responsible for collections activities, vacations and sickness fill-ins as well as customer emergency orders. Ex. KB-D at 2-4.

Having reviewed the testimony regarding meter reader/field service representative cutbacks, the Commission concludes that the proposed reductions do not match the justifications put forward by WVAWC. Instead of relying on radio read meters in Huntington or Charleston, the testimony shows that radio read meters are a relatively small portion of the total meter count in both locations. With planned reductions in capital spending on distribution system infrastructure, WVAWC does not appear to be prepared to change that fact in the near future. The Commission is also concerned that the elimination of these positions will likely lead to decreased collection activities and increased response time to customer service issues and emergencies. Thus, the Commission does not support these staff terminations and does not believe it is warranted.

Further, testimony from Ms. Bonnette casts doubt on the degree of savings the radio read meters would offer if deployed in greater numbers. The Commission finds that the testimony in this proceeding substantially undercuts the justification for meter reader/field service representative reductions in the Kanawha Valley and Huntington Districts. The Commission believes that sufficient meter reading/field service representative positions are essential to accurate billing, effective collection efforts, appropriate response to customer service needs and overall customer satisfaction while simultaneously assuring that WVAWC obtains the revenue to which it is entitled by this Commission. Therefore, the Commission concludes that these layoffs are unreasonable and will instead direct WVAWC to retain two of the meter reader positions in the

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[8] This Commission has had and continues to have reservations about the tremendous claims made before this Commission by utilities for accuracy, dependability and efficiency for radio read meters and found Ms. Bonnette's testimony to be credible. For that reason, the Commission has asked for information in the monitoring reports discussed below to also include information about radio read meters.

Kanawha Valley District and an additional two of the proposed meter reader/field service representative positions for the Huntington District.

WVAWC is also directed to refrain, at this time, from reducing its employee level below 289 positions in order to accomplish the same end by other means.

F. Capital Investment

In addition to the proposed layoffs, WVAWC announced that it intends to reduce the level of capital spending on physical plant, particularly the replacement of aged distribution system infrastructure. The Commission notes that the proposed terminations are not necessarily connected to reduced capital spending on distribution infrastructure because WVAWC contracts out much of its capital investment in infrastructure as Mr. Lanham noted in his testimony. Ex. GL-D at 10, 11. Although the level of capital spending by WVAWC has actually increased slightly, WVAWC has diverted a substantial portion of its capital spending into an AWWC initiative to replace its customer service and accounting software. The net result of the change in capital spending patterns is an increase in the current replacement cycle from an equivalent 600-year main line replacement cycle to an equivalent 950-year cycle. Ex. WDM-R at 3, Ex. IF-D at 7, 8. This projected increase is despite the Commission granting WVAWC the use of AFFAC, an accounting allowance to permit WVAWC to earn a return on certain physical plant investments between rate proceedings.

The recording of AFFAC by WVAWC would permit the appropriate investment in distribution system improvements without erosion of net income, while at the same time assuring future cash recovery from ratepayers of all the amounts deferred through the AFFAC accounting mechanism. AFFAC would also allow WVAWC to capitalize its labor costs for capital spending on qualified plant. WVAWC informed the Commission by letter filed on June 10, 2011, that it intended to take advantage of AFFAC and outlined how it planned to utilize this accounting mechanism. Although the Commission is encouraged that WVAWC decided to avail itself of the AFFAC mechanism, AFFAC is essentially useless without capital investment in the replacement of aging and likely deteriorating distribution plant. The Commission concludes that an effective 950-year main line replacement cycle is impractical and unacceptable, contrary to good utility practice and will result in increased main breaks, increased customer outages in both numbers and duration, increased unaccounted for water and a degradation of service over time and is inconsistent with the essential obligation of a public utility to maintain its utility system. See, Ex. GL-D at 11, 12. The Commission rejects the level of investment in distribution system infrastructure investment WVAWC plans to make as inadequate to maintain acceptable service. Instead, the Commission expects, particularly in light of the AFFAC mechanism, that WVAWC will demonstrate substantial progress in replacing aging and deteriorating distribution plant going forward. We certainly prefer to see rate base growing for such distribution infrastructure improvement than to see capital dollars dedicated to software. Current replacement of accounting and customer service software may be convenient, but neglecting distribution system infrastructure spending over time is shortsighted and not in the best interest of WVAWC or its customers.

G. Conclusions Regarding Terminations

Considering the evidence presented in this case, the Commission will dissolve the interim injunctive relief that it imposed on May 31, 2011, except for the ten staffing positions in the three instances identified above. In regard to the (i) Kanawha Valley and Huntington District valve crews along with the associated valve program, (ii) the eliminated position in Webster Springs, (iii) two eliminated meter reader positions in the Kanawha Valley District and (iv) two meter reader/field service positions in the Huntington District, the Commission directs WVAWC to maintain those positions and programs through the conclusion of the next general rate proceeding or until further order of the Commission. As discussed earlier, WVAWC is prohibited from either eliminating those positions or taking actions that would have a similar effect, such as reduction of staffing levels in areas not previously included in the plan under consideration in this proceeding.

The Commission reiterates that allowing WVAWC to otherwise reduce its staffing levels is not an endorsement of its decisions, but merely allowing WVAWC management the freedom to operate its business and assume full responsibility for the outcomes. The timing of these reductions and the sudden revelation of "operating efficiencies" supporting the reductions is suspect, and the Commission will review the data generated from the monitoring program described below. Further, the Commission expects WVAWC to take advantage of the investment incentives offered through AFFAC. If its management decisions fail to deliver adequate utility service, the Commission may impose further requirements or take further actions to assure adequate service that meets acceptable customer service levels.

H. Monitoring

In their direct testimony, CAD and Staff recommended that the Commission direct WVAWC to collect statistical information on aspects of its customer service to assure that WVAWC service quality does not decline below acceptable levels. CAD recommended that the Commission require monthly disclosure by district of (i) the amount of non-revenue water (NRW) and unaccounted for water (UFW), (ii) miles of lines surveyed, (iii) average response time, (iv) number of boil water advisories, (v) number of leaks repaired and (vi) number of meters tested for each size of meter. Ex. BLH-D at 9. CAD also requested annual 2010 statistics for each category as a benchmark. Id. at 10. Staff recommended a similar monitoring system, but also included tabulations of the number of reported leaks and the number of either meter edits or re-reads each month. Ex. IF at 10. Staff recommended collecting the statistics for a period of two years and filing the information as closed entries in this case. Id. at 9.

Although UWUA asserted that monitoring is insufficient to remedy the harm it argued would result from the WVAWC staffing reductions, it does not object to collecting service quality statistics. Ex. GL-R at 1. It also recommended that the Commission direct WVAWC to collect data on boil water advisories that explain the circumstances surrounding each advisory and the method that WVAWC employed to inform the public. Finally, UWUA suggested monitoring the reliability of system valves. Id. at 8.

In response to the direct testimony filed by the CAD and Staff, WVAWC consented to the monitoring system they proposed. WVAWC recommended monthly reporting for one year with quarterly reporting for a second year if necessary. It also consented to furnishing similar 2010 data as a benchmark, except for certain response time and meter testing data. Ex. WDM-R at 6, 7.

The Commission has reviewed the proposed monitoring and concludes that the data requested by Staff, CAD and UWUA will be useful for tracking WVAWC service quality. The proposed program should help to alert the Commission to any unacceptable decline or downward trend in service quality. The Commission will also include additional metrics it believes are necessary to properly assess service quality. The service metrics below will be for both quarterly and year-to-date (YTD) periods, and will include comparisons to the same period information (totals only) for 2010, unless otherwise indicated by the Commission. At this juncture, the Commission will direct WVAWC to begin immediately tracking the following data for quarterly reports to the Commission including:

1. Listing of line leaks or breaks by date and time reported, date and time repaired and a description of the type and vintage of pipe. WVAWC should also include summary totals compared to the same quarterly and YTD totals for the prior year.
2. Average Response time to repair leaks, breaks or other service interruptions (other than Priority 1 which require an immediate response).
3. Average Response time to Priority 1 (emergency) service interruptions.
4. Amount of water sold (total gallons), amount of NRW, amount of UFW, amount of water delivered to system (System Delivery), and percentages of UFW and NRW on a rolling twelve month basis.
5. Listing of boil water advisories issued, by date and length of duration, along with a description of the underlying circumstances and causes. Summary totals should include a comparison to the same quarterly and YTD totals for the prior year.
6. Number of estimated meter reads and percentage of estimated meter reads to total meters.
7. Number of shut-off for non-payment orders completed and percentage to total shut-off work orders issued to field operations.

8. Rolling twelve month percentage of charged-off revenue to total billed revenue.
9. Number of meter reading edits or rereads and percentage to total meters read. List radio read meters separately.
10. Miles of main surveyed under leak detection program.
11. Number of 5/8 and 3/4 inch meters tested or replaced compared to the number of annual meters required to meet the Commission approved fifteen-year length of service program.
12. Number of meters tested by each size one-inch and above compared to the number of annual meters of each size required under Water Rule 6.4.
13. Number of informal and formal customer complaints filed with the Commission.
14. Number of valves operated, further broken down as to number of valves operated under normal operations and those operated as part of the scheduled valve operation program. The valves should also be categorized as those thirty-six inch and above, those sixteen inch to thirty-six inch and those under sixteen inch diameter. This information should be compared to the number of valves required to be operated annually by the three size classes under the current WVAWC valve operation policy/procedure.
15. The number of employees.
16. Quarterly, YTD and twelve month income statements, balance sheets and cash flow statements.
17. Quarterly, YTD and twelve month operations and financial reports presented to the WVAWC Board of Directors.

WVAWC must commence compiling the data listed herein with the quarter beginning October 2011 and within thirty days from the close of each quarter provide that data to each party to this action and file a copy with the Commission as a closed entry under this case number. The quarterly reporting will continue through the quarter ending December 2013, unless modified by Order of this Commission.

The Commission also concludes that data from 2010 would serve as a useful benchmark for comparison with future data. Therefore, WVAWC must tabulate the data the Commission has directed it to collect in this Order from 2010 and include that information with the first quarterly report. In the event that WVAWC cannot provide a category of 2010 data, it should file a written explanation with its first report.

I. Protective Treatment

WVAWC has requested that the Commission issue a protective order for several documents including (i) an unredacted version of Company Ex. 1 that WVAWC filed on June 6, 2011, along with its answer, (ii) the WVAWC response to discovery request CAD 1-1(b) from which CAD derived CAD Cross Ex. 4, (iii) the WVAWC response to

Staff request 1.7, (iv) responses to UWUA discovery responses 1-4-1 and 1-17 filed on June 27, 2011, and (v) LIUNA Cross Ex. 2. WVAWC asserted that these documents contained data that are either trade secrets or confidential employee information exempted from the West Virginia Freedom of Information Act, codified as W.Va. Code §29-1-1 et seq. (WV FOIA). It argued that it has handled the allegedly confidential materials in accord with the factors set forth in State ex rel. Johnson v. Tsapis, 187 W. Va. 337, 419 S.E. 2d 1 (1992). Therefore, WVAWC requested that the Commission continue to hold the data subject to its request under seal. LIUNA joined WVAWC in its request to the extent that it includes compensation and benefit levels of individual employees. WVAWC Motion for Protective Order.

In addition to the materials directly subject to the WVAWC Motion for Protective Order, several other documents are currently held under seal because they include information derived from the items listed in the WVAWC Motion for Protective Order. This category of sealed information includes (i) a confidential version of the direct testimony of Byron Harris, (ii) CAD Cross Ex. 4 and (iii) the transcript of the closed portion of hearing testimony taken on July 26, 2011.

As noted by WVAWC, the sealed documents fall into two general categories. The first category includes items containing wage and salary information traceable to individual employees. This type of information is contained in (i) the confidential attachment to the June 6, 2011 Answer that WVAWC subsequently filed in redacted form as Company Ex. 1, (ii) the response to CAD discovery request CAD 1-1(b), (iii) CAD Cross Ex. 4 that was derived from CAD discovery request CAD 1-1(b), (iv) the sealed portion of the hearing transcript discussing that exhibit and (v) the response to UWUA data request 1-17. The Commission has repeatedly taken steps to protect specific employee wage or benefit information and will therefore grant that portion of the WVAWC motion. See, Mountaineer Gas Company, Case No. 86-604-G-42T, (Hearing Examiner Order, February 6, 1987). The Commission will direct its Executive Secretary to seal that information from public disclosure and instructs the parties to this matter to handle the information in like manner as detailed in the relevant ordering paragraph below.

The Commission, however, rejects the request to seal the redacted portions of LIUNA Cross Ex. 2. While several exhibits in this proceeding have employee information directly traceable to individual employees, the collective bargaining agreement does not contain similar specificity. Further, the Commission cannot find that the information meets the factors the Commission considers under Tsapis because the document is known outside WVAWC since it was negotiated with an outside entity. Therefore, the Commission rejects the assertion that LIUNA Cross Ex. 2 is a trade secret and denies that portion of the WVAWC protective treatment motion.

The second category of documents subject to the WVAWC motion is financial information or operating procedures that WVAWC asserted to be trade secrets. These documents include (i) the sealed version of the direct testimony of Byron Harris, Ex.

BLH-D, (ii) the response to Staff request 1.7 and (iii) the reply to UWUA request 1-4. The Commission has reviewed each of these documents and cannot conclude that the savings projections and other information in either the reply to the Staff data request or discussed in the testimony of Mr. Harris are trade secrets as defined by the WV FOIA. The Commission does not believe that release of this data would harm the ability of WVAWC to compete to the limited extent that WVAWC has competition. Similarly, the Commission cannot conclude that the data produced in response to UWUA 1-4 represents a trade secret or data qualifying under any other exception to WV FOIA. Therefore, the Commission denies the portion of the July 29, 2011 Motion for Protective Order relating to these documents.

Finally, the Commission notes that WVAWC neglected to file an affidavit attesting to the assertions contained in its protective treatment request. Therefore, the Commission will direct WVAWC to file an affidavit attesting to the facts contained in its motion within ten days of the entry of this Order. If WVAWC does not file the supporting affidavit, the Executive Secretary will release all materials under seal into the public file.

FINDINGS OF FACT

1. WVAWC planned to reduce capital spending on main and service line replacement, resulting in a 950-year main line replacement cycle. Ex. WDM-R at 3.

2. The Commission urged WVAWC to diligently control costs in response to the current economic climate. Case No. 08-0900-W-42T (Commission Order, March 25, 2009) at 7, 2010 Rate Order at 1, 10.

3. The Commission granted AFFAC to WVAWC, allowing it to earn a return on certain capital investments pending the next general rate proceeding. 2010 Rate Order at 66.

4. WVAWC provided testimony explaining most of its proposed terminations. Ex. WDM-D, Ex. DRA-D.

5. WVAWC planned to eliminate most of its existing valve program and dedicated valve crews in the Kanawha Valley and Huntington Districts. Ex. DRA-D at 7, 10, Tr. I at 143-145.

6. Operable system valves allow WVAWC employees to isolate the effect of line breaks and facilitate repairs. Ex. GL-D at 20, 22.

7. Existing valves are periodically obstructed by road paving and other construction activities. Id. at 23.

8. Abandoning the current valve program will likely result in higher costs to WVAWC and enlarge the number of customers affected by line breaks. Id. at 22.

9. Webster Springs is geographically isolated from other portions of the WVAWC system.

10. Eliminating a position in the Webster Springs District will hamper WVAWC efforts to respond to emergencies or line breaks at certain times, particularly in adverse weather. Id. at 12, 13.

11. Radio read meters serve approximately fifteen percent of WVAWC customers in the Kanawha Valley District. Id. at 10, 11.

12. Radio read meters serve fewer than ten percent of WVAWC customers in the Huntington District. Ex. KB-D at 8.

13. Radio read meters have consistently accounted for a disproportionate number of requests to re-read meters in the Huntington District. Id., Tr. II at 77.

14. Staff and CAD requested that the Commission direct WVAWC to track statistical data to monitor the effect of the proposed terminations on service quality. Ex. BLH-D at 9, Ex. IF at 10.

15. WVAWC can produce statistical information from 2010 as a benchmark for future service quality monitoring. Ex. BLH-D at 10.

16. WVAWC agreed to the monitoring program Staff and CAD proposed for a period of up to two years. Ex. WDM-R at 6, 7.

17. UWUA does not object to a monitoring program, but recommended collecting additional information regarding line breaks and boil water advisories. Ex. GL-R at 1, 8.

18. WVAWC requested protective treatment for documents filed under seal, including an exhibit filed on June 6, 2011, and certain discovery responses to Staff, CAD and UWUA. It also requested that treatment for the unredacted version of LIUNA Cross Ex. 2. The documents contain either employee specific data or financial information relating to the terminations. Motion for Protective Order.

CONCLUSIONS OF LAW

1. The Commission has the authority to investigate utility practices that appear to interfere with that utility's ability to provide and maintain service quality, and on sufficient evidence thereof, to direct remedial or preventative measures. W.Va. Code

§§24-1-1, 24-2-7, Syl. Pt. 2 of United Fuel Gas Company, et al. v. PSC, 154 W.Va. 221, 174 S.E. 2d 304 (1969).

2. The scope of this general investigation focused on the May 2011 terminations, their justification, their likely impact on service quality and the effect of underlying capital spending decisions on those layoffs. June 9, 2011 Commission Order.

3. The terminations WVAWC proposed are generally supported by testimony WVAWC provided, except for the three categories of employees the Commission directs WVAWC to retain. W.Va. Code §§24-1-1, 24-2-7.

4. Eliminating a systematic valve program and the dedicated valve crews in the Kanawha Valley and Huntington Districts and simultaneously limiting capital investment in distribution infrastructure are unreasonable utility practices that the Commission should prevent by directing WVAWC to retain the program and the five associated positions. W.Va. Code §§24-1-1, 24-2-7.

5. Eliminating a position assigned to the Webster Springs District that reduces staffing in Webster Springs to a single employee on certain days is an unreasonable utility practice that the Commission should prevent by directing WVAWC to retain the affected position. Id.

6. Eliminating certain meter readers/field service representatives from the Kanawha Valley and Huntington Districts is an unreasonable utility practice that the Commission should prevent by directing WVAWC to retain two of the terminated positions in each location. Id.

7. The elimination of the valve program and valve crews, elimination of the position in Webster Springs and the elimination of certain meter readers/field service representatives from the Kanawha Valley and Huntington Districts are unreasonable practices that will adversely affect quality of service.

8. It is reasonable, based on the facts of this case, that WVAWC maintain a minimum staffing of 289 positions until further order of the Commission or the conclusion of its next rate case that will involve a review of staffing, costs and rates in detail.

9. An effective 950-year main line replacement cycle is unreasonable, contrary to good utility practice and fails to utilize the recent accounting treatment the Commission awarded in the 2010 Rate Order.

10. The level of investment in distribution system infrastructure investment WVAWC plans to make is inadequate to maintain acceptable service; instead, and particularly in light of the AFFAC mechanism, the Commission expects WVAWC to

demonstrate substantial progress in replacing aging and deteriorating distribution plant and reducing its distribution infrastructure replacement cycle. Id.

11. The data collection CAD, Staff and UWUA proposed is reasonable for tracking WVAWC service quality along with the supplemental data listed in Discussion Section H above.

12. Quarterly reporting of monitoring statistics for two years will be adequate to review WVAWC service quality without creating an undue burden.

13. Requiring quarterly service quality reports to assure that WVAWC service does not fall to unacceptable levels will allow the parties and the Commission to react promptly to future quality of service problems.

14. The redactions from Ex. BLH-D, LIUNA Cross Ex. 2, the response to Staff request 1.7 and the reply to UWUA request 1-4 are not trade secrets under WV FOIA.

15. Information contained within (i) the confidential attachment to the June 6, 2011 Answer that WVAWC subsequently filed in redacted form as Company Ex. 1, (ii) the response to CAD discovery request CAD 1-1(b), (iii) CAD Cross Ex. 4 that was derived from the response to CAD discovery request CAD 1-1(b), (iv) the sealed portion of the hearing transcript discussing that exhibit and (v) the response to UWUA data request 1-17 are exempt from WV FOIA because they contain trade secrets or information of a personal nature that should be kept from public disclosure by the means described in the relevant ordering paragraph below. Mountaineer Gas Company, Case No. 86-604-G-42T (Hearing Examiner Order, February 6, 1987), W.Va. Code §29B-1-4(a)(2).

ORDER

IT IS THEREFORE ORDERED that the May 31, 2011 interim relief Order that enjoined WVAWC from involuntarily reducing staffing levels is dissolved, except for the proposed layoffs involving (i) the Kanawha Valley and Huntington District valve crews, (ii) the eliminated position in Webster Springs, (iii) two eliminated meter reader positions in the Kanawha Valley District and (iv) two eliminated meter reader/field service representative positions in the Huntington District. WVAWC is directed to maintain those positions through the conclusion of the next general rate proceeding or until further order of the Commission. WVAWC shall also maintain the existing valve program.

IT IS FURTHER ORDERED that WVAWC shall maintain a minimum complement of 289 positions.

IT IS FURTHER ORDERED that WVAWC shall, at a minimum and until further order of the Commission, maintain capital spending at a level that demonstrates substantial progress toward reducing its distribution infrastructure replacement cycle.

IT IS FURTHER ORDERED that WVAWC shall immediately begin collecting the statistical information described in Discussion Section H above.

IT IS FURTHER ORDERED that WVAWC shall file quarterly reports containing the statistical information required by this Order within thirty days after the close of each quarter beginning with the quarter ending December 31, 2011, through December 31, 2013, unless otherwise directed.

IT IS FURTHER ORDERED that with the first quarterly statistical report, WVAWC shall file historical information for each data category from 2010 or provide a written explanation for the lack of that data.

IT IS FURTHER ORDERED that WVAWC Motion for Protective Order is denied with respect to (i) the redactions from Ex. BLH-D, (ii) LIUNA Cross Ex. 2, (iii) the WVAWC response to Staff request 1.7 and (iv) the WVAWC reply to UWUA request 1-4.

IT IS FURTHER ORDERED that the Motion for Protective Order is granted with respect to (i) the confidential attachment to the June 6, 2011 Answer that WVAWC subsequently filed in redacted form as Company Ex.1, (ii) the response to CAD discovery request CAD 1-1(b), (iii) CAD Cross Ex. 4 that was derived from the reply to CAD discovery request CAD 1-1(b), (iv) the sealed portion of the hearing transcript discussing that exhibit and (v) the response to UWUA data request 1-17.

IT IS FURTHER ORDERED that documents subject to the granted portion of the WVAWC Motion for Protective Order shall be handled as follows:

1. No party shall disclose the redacted contents of those documents or information specifically derived therefrom to the public.

2. No party shall allow copying of the redacted portion of the sealed documents or information specifically derived therefrom, without the permission of WVAWC or the Commission.

3. No party shall disclose, use or discuss the redacted portion of the sealed documents or information specifically derived therefrom with any person or entity outside of this case.

4. All parties and witnesses are prohibited from disclosing the redacted portion of these documents or information specifically derived therefrom in future open hearings, if any.

5. All parties that possess the unredacted portion of the sealed documents or information specifically derived therefrom shall destroy that information once this matter is finally concluded.

6. The Executive Secretary shall maintain any filings containing the unredacted versions of the sealed information or information specifically derived therefrom in a separate and sealed condition.

7. A party filing a document containing the unredacted sealed documents or information specifically derived therefrom shall clearly denote that fact on its filing and shall file both a redacted version excluding the protected information and a complete version of its filing under seal.

IT IS FURTHER ORDERED that WVAWC shall file an affidavit in support of its protective treatment request within ten days of the entry of this Order.

IT IS FURTHER ORDERED that on entry of this Order, this matter is removed from the active docket of Commission cases.

IT IS FURTHER ORDERED that the Commission Executive Secretary serve a copy of this Order by electronic service on all parties requesting that service, on other parties by United States First Class Mail and on Staff by hand delivery.

A True Copy, Teste: Sandra Squire

Sandra Squire
Executive Secretary

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NEVADA

Petition of the International Brotherhood of Electrical Workers Local No. 1245 to open an investigatory docket regarding the workforce staffing and planning of Sierra Pacific Power Company d/b/a NV Energy, Docket No. 10-10013, PUBLIC UTILITIES COMMISSION OF NEVADA, Order (Feb. 25, 2011).

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Petition of the International Brotherhood of Electrical Workers Local No. 1245 to open an investigatory docket regarding the workforce staffing and planning of Sierra Pacific Power Company d/b/a NV Energy.	))))))	Docket No. 10-10013

At a general session of the Public Utilities Commission of Nevada, held at its offices on February 23, 2011.

PRESENT: Chairman Alaina Burtenshaw
Commissioner Rebecca D. Wagner
Assistant Commission Secretary Breanne Potter

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

I. INTRODUCTION

The International Brotherhood of Electrical Workers Local No. 1245 ("IBEW") filed a Petition requesting that the Commission open an investigatory docket regarding the workforce staffing and planning of Sierra Pacific Power Company d/b/a NV Energy ("SPPC").

II. SUMMARY

The Commission grants the Petition and opens an investigatory docket, but limits the investigation to addressing whether SPPC's workforce is, or in the future will be, experiencing a significant amount of aging and the potential impact, if any, that such aging may have on the reliability of SPPC's service.

III. PROCEDURAL HISTORY

- On October 20, 2010, IBEW filed a Petition, designated as Docket No. 10-10013, with the Commission requesting that the Commission open an investigatory docket regarding the workforce staffing and planning of SPPC.

- IBEW filed its Petition pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), Chapters 703 and 704, including but not limited to NAC 703.540.

DOCUMENT REVIEW AND APPROVAL ROUTING

DRAFTED BY: Jordan Pinsuv

FINAL DRAFT ON 2 / 23 / 11 AT 1 : 40 P M

REVIEWED & APPROVED BY: DATE

☐ ADMIN / ASST. (______) ______ __ / __ / __

☒ COMM / COUNSEL JGJC 2 / 23 / 11

☐ SECRETARY / ASST. SEC. ______ __ / __ / __

☐ OTHER (______) ______ __ / __ / __

- On October 25, 2010, the Commission issued a Notice of Petition for Investigation of Electric Company's Workforce Staffing and Planning.
- On November 23, 2010, the Regulatory Operations Staff ("Staff") of the Commission filed comments on IBEW's Petition.
- On November 24, 2010, SPPC filed comments on IBEW's Petition.
- On November 30, 2010, IBEW filed a Motion for Leave to Reply ("Motion") in response to SPPC's comments.
- On December 8, 2010, at a duly noticed agenda meeting of the Commission ("Agenda Meeting"), the Commission voted to deny the Motion and set the Petition for further proceedings for the purpose of determining whether SPPC's workforce is, or in the future will be, experiencing a significant amount of aging and the potential impact, if any, that such aging may have on the reliability of SPPC's service.
- On January 19, 2011, the Commission issued a Notice of Prehearing Conference which established a due date of February 9, 2011 for the filing of written comments, petitions for leave to intervene, or notices of intent to participate as a commenter.
- On January 28, 2011, the Attorney General's Bureau of Consumer Protection ("BCP") filed a Notice of Intent to Intervene pursuant to NRS 228.
- On February 20, 2011, a Prehearing Conference was held. Appearances were made by BCP, IBEW, SPPC and Staff.

IV. COMMISSION DISCUSSION AND FINDINGS

1. Pursuant to NRS 703.150, "the Commission shall supervise and regulate the operation and maintenance of public utilities." Further, it is the duty of the Commission "to provide for the safe, economic, efficient, prudent and reliable operation and service of public utilities." NRS 704.001(3). Accordingly, the Commission finds that it has the authority to supervise and regulate the staffing of SPPC, a public utility, as is necessary to ensure that SPPC provides safe, economic, efficient, prudent, and reliable service to its customers.

2. On December 8, 2010, at the Agenda Meeting, the Commission's General Counsel recommended that the Commission issue an order setting IBEW's Petition for further

proceedings to further examine the necessity and, if applicable, the scope of a potential investigation into the staffing issues addressed by IBEW.

3. At the Agenda Meeting, The Commission voted to set the Petition for further proceedings, provided that the scope of such further proceedings be limited as suggested in Staff's comments. Staff's comments suggested that the Commission limit the scope of the proposed investigation to the following matters: (1) the extent to which SPPC is facing an aging workforce; (2) if Sierra Pacific is facing a significant aging of its workforce (compared to past experience), SPPC's efforts to identify and address the concerns or issues raised by a significant aging workforce; and (3) whether, how, and the extent to which SPPC's potentially significant aging workforce might affect the reliability of SPPC's service.

4. The Commission finds that additional evidence is not necessary to determine whether an investigation is appropriate. The issues raised by IBEW in its Petition warrant the opening of an investigatory docket, therefore the Petition to open an investigatory docket should be granted. However, as discussed by the Commission at the December 8, 2010 Agenda Meeting, the scope of the investigatory docket should be limited to addressing the matters outlined in Staff's comments and restated in Paragraph 3 of this Order.

THEREFORE it is ORDERED that:

1. The Petition of the International Brotherhood of Electrical Workers Local No. 1245, designated as Docket No. 10-10013, is GRANTED as MODIFIED by this Order.

2. The Commission shall OPEN AN INVESTIGATORY DOCKET to investigate the following matters: (1) the extent to which SPPC is facing an aging workforce; (2) if Sierra Pacific is facing a significant aging of its workforce (compared to past experience), SPPC's efforts to identify and address the concerns or issues raised by a significant aging workforce; and

(3) whether, how, and the extent to which SPPC's potentially significant aging workforce might affect the reliability of SPPC's service.

3. The Commission retains jurisdiction for the purpose of correcting any errors that may have occurred in the drafting or issuance of this Order.

By the Commission,

ALAINA BURTENSHAW, Chairman and
Presiding Officer

REBECCA D. WAGNER, Commissioner

Attest: ______________________
BREANNE POTTER,
Assistant Commission Secretary

Dated: Carson City, Nevada

2-25-11

(SEAL)

PUBLIC UTILITIES COMMISSION OF NEVADA
PUC

VERMONT

Investigation into Cent. Vt. Pub. Serv. Corp.'s Staffing Levels, Docket No. 7496, VERMONT PUBLIC SERVICE BOARD, Order (Aug. 20, 2009).

STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 7496

Investigation into Central Vermont Public Service Corporation's staffing levels	)))	Hearing at Montpelier, Vermont June 10, 2009

Order entered: 8/20/2009

PRESENT: James Volz, Board Chair
David Coen, Board Member
John Burke, Board Member

APPEARANCES: Dale A. Rocheleau, Esq.
Morris L. Silver, Esq.
For Central Vermont Public Service Corporation

Geoffrey Commons, Esq.
For Vermont Department of Public Service

I. INTRODUCTION

This investigation concerns the question of whether Central Vermont Public Service Corporation ("CVPS" or "the Company") is maintaining an appropriate staffing level for an electric utility of its size. We opened this investigation upon the joint request of CVPS and the Vermont Department of Public Service ("Department" or "DPS"), pursuant to the terms of their settlement in CVPS's most recent rate case proceeding.[1] Today, we direct CVPS to implement the recommendation of the Huron Consulting Group ("Huron") that CVPS undertake a comprehensive review of its organizational structure and staffing levels and costs to determine

1. Docket 7485, *Investigation into Central Vermont Public Service Corporation's rates in effect, on a bills-rendered basis, as of January 1, 2009*, Order of 2/13/09 at 3.

the appropriate structure and number of staff the Company should employ at ratepayer expense.[2] In addition, we determine that it is appropriate to increase the 2010 non-power-cost cap established in CVPS's alternative regulation plan to recognize the Company's actual level of employees.

II. Procedural History

On February 13, 2009, in response to a joint request from CVPS and the Department, the Public Service Board ("Board") opened an investigation into the staffing levels of CVPS.

On March 25, 2009, the Board convened a prehearing conference in this matter. Appearances were entered by Geoffrey A. Commons, Esq., on behalf of the DPS; and Dale A. Rocheleau, Esq., on behalf of CVPS.[3]

On April 10, 2009, the Department filed direct testimony.

On April 15, 2009, CVPS served upon the Department the first of three rounds of discovery regarding the Department's direct testimony.

On May 1, 2009, CVPS filed direct testimony.

On May 6, 2009, the Department served upon CVPS the first of two rounds of discovery regarding CVPS' direct testimony.

On May 22, 2009, the Department advised the Clerk of the Board via electronic mail that it would not be filing any rebuttal testimony in this proceeding.

On June 8, 2009, the Department filed a revised version of Exhibit DPS-RWB-1 to the direct testimony of witness Ronald W. Behrns.[4]

On June 10, 2009, the Board convened a technical hearing in this proceeding in Montpelier, Vermont.

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2. Huron made this recommendation to CVPS in its report at the conclusion of a business process review performed by Huron pursuant to a settlement reached between the Department and CVPS in Docket 7321. *See* Exh. CVPS-1 at ch. VI, p. 83 (hereinafter also referred to as the "Huron Report").

3. On April 15, 2009, a notice of appearance on behalf of CVPS also was filed by Morris L. Silver, Esq.

4. This document was later admitted into the evidentiary record as Exhibit DPS-1.

On June 16, 2009, the DPS filed a further revised version of Exhibit DPS-RWB-1, which corrected an error pointed out at the technical hearing and replaces Exhibit DPS-1 that was admitted into evidence at the technical hearing.

On July 1, 2009, the Parties filed initial briefs.

On July 17, 2009, the Parties filed reply briefs.

Also on July 17, 2009, in response to a record request made by the Board during the technical hearing, CVPS filed an exhibit consisting of printouts of CVPS's exempt employee time tracking screens that are currently in use as a part of CVPS's computer-assisted accounting system. CVPS's filing stated that it had no objection to the admission of this document into evidence. At the technical hearing, the DPS stated it had no objection to the admission of the printout of exempt employee time tracking screens into evidence.[5] Accordingly, we are admitting this document into evidence as Exhibit Board-3.

III. FINDINGS

Based on the evidence in the evidentiary record in this docket, we hereby make the following findings.

1. Approximately half of CVPS' workforce consists of salaried employees who are exempt from the terms of any collective bargaining agreements CVPS has with its union employees ("exempt employees"). Tr. 6/10/09 at 185-186 (Beraldi); exh. DPS-1 at 1, lines 1-24.

2. CVPS monitors the productivity of its employees through management observation and communication. Exh. DPS-cross-4.

3. Exempt employees typically report working 40 hours per week, regardless of how many hours they actually work. Tr. 6/10/09 at 214 (Beraldi) and 245-246 (White).

4. No documentation exists to verify whether CVPS' exempt employees regularly work in excess of 40 hours per week. White/Beraldi pf. at 19; tr. 6/10/09 at 214 (Beraldi).

5. In proportional terms, CVPS has more employees than either of Vermont's other large utilities, Green Mountain Power Corporation ("GMP") or Vermont Electric Cooperative, Inc. ("VEC"), when measured against the following comparative baselines:

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5. Tr. 6/10/09 at 205-206 (Commons).

- Square miles of territory served
- Net utility plant in service
- Revenue generated in 2008
- Number of customers served.

Behrns pf. at 5; exh. DPS-1 at 1.

6. These comparative baseline measures form the basis of the Department's "benchmark" analysis. This analysis suggests that additional inquiry could explain the staffing-level differences between CVPS and GMP and VEC. Behrns pf. at 6.

7. Comparing CVPS' staffing levels and operational costs to those of GMP and VEC is appropriate because all three companies operate in similar geographical territory, are regulated in like fashion and participate in the same power market to purchase power. Tr. 6/10/09 at 169-172, 250, and 261-262 (White/Beraldi).

8. CVPS's non-power costs per customer are higher than those of GMP and VEC. Exh. DPS-1 at 2.

9. Judging by the Department's "benchmark" analysis, CVPS has 2.8 times more employees than GMP and 5.6 times more employees than VEC. Behrns pf. at 5; exh. DPS-1 at 1.

10. The functional areas where CVPS's staff levels appear to deviate most in proportional terms from GMP and VEC are corporate services, human resources, information technology, finance and transportation. Exh. DPS-1 at 1; tr. 6/10/09 at 112-114 (Behrns).

11. In the category of field workers such as linemen, it is possible that the difference in employee headcount between GMP and CVPS is due to differences in the number of square miles of service territory or distribution line miles each company is responsible for maintaining and servicing. Behrns pf. at 6.

12. Any difference in staffing numbers between CVPS and GMP due to line miles should be expected to manifest in the number of linemen and engineers these companies employ, but not in the areas such as finance or accounting. Behrns pf. at 6.

13. In Vermont, power and transmission costs typically make up approximately 70-80 percent of an electric utility's cost of service. By comparison, CVPS's ratio is closer to 52 percent. Behrns pf. at 8.

14. CVPS's comparatively favorable power/transmission cost ratio is due to the fact that at present, CVPS's major power contracts are priced below market prices. This advantage is likely to change in approximately three years. Behrns pf. at 8; tr. 6/10/09 at 169-174 (White).

15. Beginning in 2012, there is likely to be significant upward pressure on CVPS' rates; the need for CVPS to manage staffing and other expenses more closely will increase as well. Exh. CVPS-1 at ch. VI, p. 38.

16. CVPS should be taking steps now to bring its non-power/transmission costs into line with those of other Vermont utilities. Behrns pf. at 8.

17. The Department believes its "benchmark" analysis of CVPS' present staffing levels suggests that ratepayers could be paying up to $9 million annually due to an excessive headcount. Tr. 6/10/09 at 101 (Behrns).

18. The Department has not offered any specific data showing that CVPS has an excessive headcount in any one area of its operations. Behrns. pf. at 8.

19. The Department's "benchmark" analysis does not account for differences in the corporate structures of CVPS, GMP and VEC. White/Beraldi pf. at 11-12.

20. The structural differences between CVPS, GMP and VEC may have a significant impact on the compliance and reporting requirement for each of these companies, which, in turn, may affect the number of employees each company needs. White/Beraldi pf. at 13.

21. The Department's "benchmark" analysis does not account for differences in the headcounts of CVPS, GMP and VEC due to the effects of in-sourcing functions as opposed to out-sourcing them. White/Beraldi pf. at 13.

22. The Department's "benchmark" analysis reflects no information from GMP or VEC about the number of hours that their exempt employees work above 40 hours per week. Tr. 6/10/09 at 73 (Behrns).

23. CVPS' current organizational structure has not been reviewed on a comprehensive basis in recent years to determine whether it is the most cost-effective structure. The Company appears to have some layers of management and spans of control that may not be aligned with CVPS's functional and organizational needs. Exh. CVPS-1 at ch. VI, pp. 33-35.

24. In July 2008, CVPS had 556 employees. As of the end of April 2009, CVPS had 545 employees. Tr. 6/10/09 at 167 (Beraldi).

IV. Discussion

This investigation is the result of a disagreement between the Department and CVPS as to the appropriateness of CVPS's staffing levels. As part of a rate case settlement approved by the Board in January of 2008, CVPS and the DPS agreed that they would jointly select an expert consultant to undertake a Business Process Review that would examine, among other items, CVPS's staffing levels.[6] The Department and CVPS agreed to retain Huron, who completed the Business Process Review in October 2008 and generated a report detailing their conclusions in the Huron Report. However, because of disagreements between CVPS and the Department concerning the scope and methodology used by Huron in analyzing the Company's staffing levels, the Huron Report did not provide a "conclusive recommendation" regarding CVPS's staffing levels.[7] Consequently, Huron recommended that CVPS pursue another, more comprehensive review of its organizational structure and staffing levels and costs.[8]

Dissatisfied with the outcome documented by the Huron Report, the Department has continued to press its concerns about CVPS's staffing levels, notably in Docket 7336, in which the Company's alternative regulation plan was reviewed and approved, and again in Docket 7485, in which these parties settled CVPS's most recent rate increase request by agreeing to jointly petition the Board for the staffing level investigation that now is the subject of this docket. In our order approving the settlement in Docket 7485, we made the following finding:

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6. Docket 7321, Tariff Filing of Central Vermont Public Service Corporation Requesting a 4.46% increase in its rates, effective June 29, 2007, for implementation as of February 1, 2008, Order of 1/31/08 at 6.

7. Exh. CVPS-1 (*Cover letter from F. Wayne Lafferty, Huron Consulting Group, to Joseph Kraus, Vice-President - Operations and Engineering, CVPS and Stephen Wark, Director, Consumer Affairs & Public Information Division, DPS*, dated October 13, 2008, at 2).

8. Exh. CVPS-1, ch. VI at 83. The Huron Report specifically noted that "a narrow review of just headcount will not provide an adequate assessment of CV's cost structure especially when comparisons are made to other utilities which may outsource different functions, have different types of operating territories, follow different accounting practices or exhibit other variances in operating characteristics." *Id.* at 83-84.

> Upon conclusion of the docket concerning CVPS staffing levels, the non-power cost cap applicable to the next base rate filing under the CVPS plan will be adjusted, as warranted, to reflect the outcome of that docket.[9]

In this Order, we address first the general issue of CVPS's staffing levels, followed by the effect of our conclusions in this area on the calculation required by CVPS's alternative regulation plan.

Tracking Actual Hours Worked

In this case the Department has sought an order requiring CVPS to track actual hours worked by salaried employees (also called "exempt" employees). Such employees make up about half of CVPS's work force, and presently do not keep any records of the time actually spent working. The DPS has long been concerned that CVPS is over-staffed, which means ratepayers are funding an inefficient and excessively costly operation. To support its position, the Department has offered a "benchmark" analysis – a comparison of CVPS's non-power costs to those of GMP and VEC – the two most similarly-situated utilities in Vermont. However, the Department concedes that its benchmark comparison does not conclusively prove that CVPS is over-staffed. Therefore, in order to prepare for a more rigorous and conclusive review of CVPS' staffing levels at a future point in time, the Department believes a useful starting point would be for CVPS to now begin tracking the actual hours worked by its exempt employees.

CVPS rejects any contention that it is overstaffed, and therefore opposes the Department's proposal, arguing that the hour-tracking requirement would cause demoralizing disruption for its employees and constitutes an intrusion upon the Company's management of its affairs that the Department has failed to justify, as there has been no showing that CVPS is failing to conduct its business "so as to be reasonable and expedient, and to promote the safety, convenience and accommodation of the public" as required by 30 V.S.A. § 209(a)(3). The Company further takes

9. Docket 7485, Order of 2/13/09 at 4 (finding 10).

issue with the Department's proposed tracking requirement because it is not likely to yield information that can reasonably be used to improve CVPS's productivity or efficiency.[10]

CVPS contends that it "should be accorded discretion to implement such strategies and systems as it determines will enable the Company to operate in accordance with its obligations to its stockholders and the public."[11] Therefore, according to CVPS, this investigation should be closed because "the evidence supports a conclusion that the Company's staffing levels and costs are reasonable."[12] The Department counters that the evidence in fact supports a finding that the Company's staffing levels are unreasonable, and that CVPS "has not shown any sufficient basis for its inordinately high employee count or for its excessive costs per customer."[13]

We are mindful that Vermont law has long established that utilities are vested with significant discretion to manage their operations. The Vermont Supreme Court has held that the function of the Board is one of control, not management, in reviewing a utility's actions.[14] However, Vermont law also charges the Board with broad powers to ensure that utilities conduct their business in a fashion that is consistent with the public good. Specifically, the Board has jurisdiction to hear, determine, render judgment and make orders and decrees in all matters concerning:

> the manner of operating and conducting any business subject to supervision under this chapter, so as to be reasonable and expedient, and to promote the safety, convenience and accommodation of the public . . .[15]

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10. The Department specifically proposes that these hours tracked should be used to measure productivity, where the hours are used as inputs for employees, including hours worked by salaried employees, and completed work load volumes are used as outputs. For efficiency measurements, the Department suggests that CVPS should establish standards for each respective work activity or task. Behrns pf. at 3.

11. CVPS Initial Brief at 11.

12. *Id.* at 13.

13. DPS Reply Brief at 2.

14. *Letourneau v. Citizens Utilities Company*, 125 Vt. 38, 41 (1965); *Petitions of New England Tel. & Tel. Co.*, 116 Vt 480, 501 (1951).

15. 30 V.S.A. § 209(a)(3).

Furthermore, the Vermont Supreme Court has recognized the Board's broad statutory authority to exercise jurisdiction over a utility to ensure that its operations are "reasonable and expedient,"[16] and, more specifically, to ensure that personnel costs borne by ratepayers are set at levels that result in just and reasonable rates.[17] Therefore, we conclude that this investigation falls well within our supervisory authority over CVPS's staffing levels and the attendant costs imposed upon CVPS ratepayers.

Turning to the Department's request that we order CVPS to begin tracking actual hours worked by its exempt employees, we decline to impose this requirement as we are not persuaded that it would yield any probative data that could lead to a conclusive assessment of the appropriateness of CVPS's staffing levels. The tracking information the Department seeks to develop is appropriate for measuring the productivity and efficiency of workers who perform repetitive tasks.[18] But CVPS's exempt employees are knowledge-based workers whose efforts are not repetitive in nature and for whose activities there are no readily-measurable standard units.[19] Nor would requiring CVPS to track actual employee hours worked answer the question as to how much time it *should* take to perform the tasks assigned to these employees, or whether the tasks were being done well.[20]

One possible basis for comparison could be data collected by other electric utilities. However, while the DPS asserts that some utilities are measuring the productivity of their exempt employees, the DPS is not aware of any specific companies that are doing so.[21]

Finally, the Department argues that the tracked-hours data will allow CVPS' staffing levels to be "objectively determined based on the work activity and work load that evolves from

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16. *In re Petition of Verizon New England,* 173 Vt. 327, 332 (2002).

17. *In re Green Mountain Power Corp.*, 162 Vt. 378, 387(1994).

18. Exh. DPS-RWB-3 at 3-5.

19. Beraldi/White pf. at 7 and 17-18.

20. Tr. 6/10/09 at 83-84 (Behrns).

21. Tr. 6/10/09 at 87-88 (Behrns).

efficient business processes . . . ."[22] But the Department admits there is a subjective element to establishing the output measures for this objective analysis that depends on exercising reasonable judgment about what the standards should be for how long it takes to generate a particular output.[23] We are not persuaded that implementing the Department's hour-tracking requirement will necessarily facilitate the objective assessment of CVPS' staffing requirements that the Department is seeking.

While we do not adopt the Department's recommended method for assessing whether or not CVPS is over-staffed, we are concerned that the question remains as to what is the appropriate staffing level for CVPS. Compared to GMP and VEC, CVPS appears to employ significantly more personnel to conduct its business. Even after allowing for variances in size of service territory and miles of lines to be served, CVPS has not satisfactorily explained why it requires demonstrably more personnel than the other large Vermont utilities to staff its operations in finance, accounting, information technology, corporate services, human resources and transportation. While we emphasize that as of this time, there has been no determination made that CVPS in fact is over-staffed, we conclude that if indeed CVPS has an excessive headcount as the Department suggests, then it is in the interests of CVPS's ratepayers and shareholders alike for the Company to begin confronting that issue now, while CVPS still enjoys the benefit of highly favorable power contracts that are due to expire in the next few years.

CVPS argues that its alternative regulation plan ("Plan") contains incentives for the Company to control costs, and that the decrease in the number of its employees from 556 in July 2008 to 545 in April 2009 is one indication that CVPS is responding to those incentives. CVPS asserts that it should be given more time to respond to the incentives contained in the Plan, since it is still in its first year of operation.

When we first approved the Plan, we found that, at that time, with the modifications we made to CVPS's original proposal, the Plan would contain several features that would create

22. Behrns pf. at 13.

23. Tr. 6/10/09 at 83-84 and 86-87 (Behrns). As Department witness Behrn testified, "You have to look at the tasks they were doing and you have to look at the data and reach a judgment, okay, about what you think on average it should have taken over that period of time." *Id.* at 83-84.

cost-control incentives. These incentives included a non-power-cost cap (discussed in more detail in the following section of this Order), an earnings-sharing mechanism that allows CVPS to retain the bulk of any earnings above its authorized return on equity, and a requirement that CVPS absorb the first $315,000 of any increases in power costs each quarter.[24] We are pleased to learn that CVPS is responding to the Plan's incentives. However, in order for the non-power-cost cap to function as it was intended, it is necessary for the cap to be set at an appropriate level. The issue of whether CVPS's staffing level is appropriate directly affects this level. Therefore, we do not see a need to provide CVPS with additional time to respond to the Plan's incentives before addressing the question of whether CVPS is over-staffed.

Instead, we require CVPS to implement the Huron Report recommendation that CVPS undertake a comprehensive review of its organizational structure and staffing levels and costs to determine the appropriate structure and number of staff the Company should employ at ratepayer expense. We recognize that such a review is estimated to cost between $500,000 and $1 million.[25] However, if the review were to support the results of the DPS's "benchmark" analysis of CVPS' present staffing levels, ratepayers could save up to $9 million annually in lower personnel costs. Therefore, we conclude that while the review will be costly, the potential benefits are large enough to justify this cost.[26]

In addition, we note that the Docket 7321 settlement agreement (in which CVPS and the DPS agreed that a business process review would be performed) stated that CVPS and the DPS expected that CVPS would implement the recommendations made by the consultant performing the business process review.[27] Our Order today is consistent with that expectation.

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24. Docket 7336, Order of 9/30/08 at 32-33.

25. Tr. 6/10/09 at 100 (Behrns).

26. The cost of hiring a consultant to conduct this review will be in addition to CVPS's other costs for providing service to ratepayers. While we expect CVPS to prudently manage the cost of this review within the parameters of the cost-control incentives provided to CVPS under its alternative regulation plan, we want to ensure that the review is comprehensive and produces a reliable result of high quality. We therefore invite CVPS to propose a means, within the context of the alternative regulation plan, to enable it to recover from ratepayers the prudently incurred costs of the consultant. We will provide the DPS with an opportunity to comment on any such proposal before ruling on its acceptability.

27. Docket 7321, Order of 1/31/08 at 7 (finding 22).

Finally, we emphasize our desire to resolve the issue of whether CVPS's staffing level is appropriate. We are troubled that this issue has arisen in four recent dockets (dockets 7321, 7336, 7485, and 7496) and we have yet to be presented with a record that would allow us to make a determination regarding the appropriateness of CVPS's staffing levels. It is our intention that the new comprehensive review of CVPS's organizational structure and staffing levels and costs will produce a clear and substantial record for resolving this issue.[28]

Therefore, we require that, within 90 days of this Order, CVPS issue a Request for Proposals ("RFP") for a management consultant to perform the comprehensive review recommended by the Huron Report. The RFP will provide for the DPS to receive copies of all proposals as well as all reports and deliverables produced by the consultant in connection with the review. CVPS must provide the DPS with an opportunity to review and comment upon the RFP prior to its issuance, as well as participate in the selection of the consultant to conduct the review, and the development of the review plan. If there are any issues regarding these matters that CVPS and the DPS cannot agree upon, CVPS must promptly bring these issues to the Board for resolution. The Board will not allow disagreement between CVPS and the DPS to unreasonably delay or halt the completion of the review. CVPS must issue a contract for the review either within 45 days following the receipt of proposals, or within 10 days after resolution of any issues by the Board, if necessary, whichever is later.

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28. The evidentiary record of this docket to date contains data gaps that we expect will not recur in the course of the comprehensive review we are ordering CVPS to undertake today. For example, we were disturbed to learn during the technical hearings that some of the analysis concerning CVPS's efficiency rested on comparisons made between CVPS and GMP and VEC, but no attempt had been made to obtain data from GMP or VEC to assess the number of overtime hours worked by these utilities' exempt employees. *See* tr. 6/10/09 at 73 (Behrns). Similarly, we are troubled by the observation in the Huron Report that there was a failure to identify an acceptable staffing analysis methodology, and that therefore Huron's staffing analysis "is incomplete, and a firm organizational structure or staffing level recommendation cannot be made at this time." Exh. CVPS-1, ch. VI, at p. 83. As we noted in our order opening this investigation, both CVPS and the DPS failed to "avail themselves of an efficient dispute resolution mechanism that they had previously agreed to use. Neither ratepayers nor shareholders are well-served by this unproductive course of conduct." Docket 7485, Order of 11/25/08 at 3.

Effect on Alternative Regulation Plan Calculation

The Plan includes a mechanism for capping base-rate increases that is designed to provide CVPS with an incentive to carefully monitor expenses and to realize cost efficiencies when prudently possible. This cap, referred to as a "non-power-cost cap," is calculated for each year that the Plan is in effect, using a formula set forth in the Board's September 30, 2008, Order approving the Plan.[29] The starting point for the calculation is the costs embedded in CVPS's base rates for the previous year.

CVPS's 2009 base rates were determined in Docket 7485.[30] These 2009 base rates would normally be the starting point for the calculation of CVPS's 2010 non-power-cost cap. However, as part of the settlement in Docket 7485, CVPS and the DPS agreed that upon the conclusion of the new investigation into CVPS's staffing levels, the non-power-cost cap applicable to the next base rate filing under CVPS's alternative regulation plan would be adjusted, as warranted, to reflect the outcome of the investigation. Thus, it is necessary for us to determine whether, given the outcome of this docket, the non-power-cost cap applicable to CVPS's 2010 base rate filing should be adjusted, and if so, how.

CVPS contends that because the Department has failed to prove in this docket that CVPS has an excessive headcount, the Company is entitled to increase its non-power-cost cap for 2010 by $945,000. According to CVPS, this amount represents the difference between the 554 full-time equivalent employees ("FTE") included in CVPS's original 2009 base rate filing, and the 542.75 FTEs included in the cost of service agreed to by CVPS and the DPS in Docket 7485.[31]

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29. Docket 7336, Order of 9/30/08 at 31-32.

30. In October 2008, CVPS made its first base rate filing under the Plan. In this filing, CVPS requested a 0.33% increase. The Board allowed this increase to go into effect for bills rendered on and after January 1, 2009, but simultaneously opened an investigation into the justness and reasonableness of CVPS's 2009 rates (Docket 7485). When Docket 7485 was settled, the parties agreed that CVPS's 2009 base rate filing would be conformed to agree in full with the terms of the settlement, and the revised tariffs attached to the settlement would supercede the tariffs previously approved by the Board for implementation effective with bills rendered January 1, 2009. Docket 7485, Order of 2/13/09 at 2.

31. We note that CVPS stated that its proposed adjustment to the non-power-cost-cap "reflects the $945,000 that was disallowed in the Company's 2009 Base Rates due to this staffing level dispute." CVPS Brief at 15. This characterization is inaccurate. The Board did not disallow any costs from CVPS's 2009 base rates. Rather, the Board approved a settlement agreement between CVPS and the DPS which stated, in relevant part, "CVPS agrees to

The DPS argues that CVPS's 2010 non-power-cost cap should be increased to recognize CVPS's actual level of employees. The DPS asserts that since, according to testimony by CVPS in this proceeding, CVPS's actual level of employees is 545, not the 554 included in the original 2009 base rate filing, CVPS's non-power cost cap should be increased by 2.25 "average" employees (approximately $189,000, which is the difference between CVPS's 545 actual employees and the 542.75 FTEs included in CVPS's 2009 base rates.

At the prehearing conference in this proceeding, the DPS stated that it no longer expected the Board to issue an order specifying an appropriate staff size for CVPS as a result of this docket. The Board discussed with the parties what effect this change in direction would have on the calculation of the 2010 non-power-cost cap, in light of the Docket 7485 settlement. The parties agreed that the 2010 non-power-cost cap would change "to recognize the actual level of employees."[32]

We determine that this agreement should be implemented. To do so, we must determine what is CVPS's actual level of employees. According to CVPS, as of July 2008, it had 556 employees, but by the end of April 2009, that number had fallen to 545. CVPS provided three reasons for the difference: permanent reductions; vacancies; and positions which the Company had yet not determined whether they would be filled.[33] We recognize that the actual number of employees at a company can fluctuate over time for a variety of reasons, including those provided by CVPS's witness. Nevertheless, 545 is the most recent number of CVPS employees in evidence in this proceeding. We, therefore, determine it is reasonable to include the costs associated with that number of employees in the 2010 non-power-cost cap. In other words, the

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forego the 0.33% rate increase scheduled to go into effect on a bills rendered basis as of January 1, 2009, . . ." Docket 7485, Order of 2/13/09 at 3 (finding 3).

32. Tr. 3/25/09 at 14 (Commons); tr. 3/25/09 at 14 (Rocheleau). We view this agreement as effectively superceding the terms of Paragraph 9 of the Memorandum of Understanding that was approved in Docket 7485. *See* Docket 7485, Order of 2/23/09, Attachment-1 at ¶ 9. The Docket 7485 settlement contemplated that a resolution of the staffing level issue would be reached in time to adjust CVPS's 2010 non-power-cost cap for the next base rate filing required under the Plan. *Id. See* also Appendix B to Attachment-1. Because our Order today does not conclusively determine whether CVPS's staff levels are reasonable, we think it is appropriate to give effect to the compromise reached by counsel on the record in open court at the prehearing conference in this docket.

33. Tr. 6/10/09 at 167-168 (Beraldi).

2010 non-power-cost cap should be increased by the costs associated with 2.25 "average" employees.

V. Conclusion

In today's Order we direct CVPS to implement the Huron Report recommendation that CVPS undertake a comprehensive review of its organizational structure and staffing levels and costs to determine the appropriate structure and number of staff the Company should employ at ratepayer expense. In addition, we determine that it is appropriate to increase the 2010 non-power-cost cap established in CVPS's alternative regulation plan to recognize an additional 2.25 "average" employees.

The Huron Report clearly articulated the need for better communication and an improved working relationship between CVPS and the DPS.[34] We are concerned that this will remain difficult to achieve until the issue regarding CVPS's staffing level is finally resolved. While institutional memory is often valuable to both utilities and regulators, in this particular instance, it is in the interest of both CVPS's ratepayers and shareholders for the DPS and CVPS to focus on the future rather than on their past conflicts. It is our intention that today's Order will set a path for a resolution of the DPS's question regarding the appropriateness of CVPS's staffing level.

VI. Order

It Is Hereby Ordered, Adjudged and Decreed by the Public Service Board ("Board") of the State of Vermont that:

1. Within 90 days of this Order, Central Vermont Public Service Corporation ("CVPS") shall issue a Request for Proposals ("RFP") for a management consultant to perform the comprehensive review recommended by the 2008 business process review conducted by the Huron Consulting Group ("Huron Report"). The RFP shall provide for the Vermont Department of Public Service ("DPS") to receive copies of all proposals as well as all reports and deliverables produced by the consultant in connection with the review.

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34. Exh. CVPS-1 at ch. IX, pp. 6-9.

2. CVPS shall provide the DPS with an opportunity to review and comment upon the RFP prior to its issuance, as well as participate in the selection of the consultant to conduct the review, and the development of the review plan. If there are any issues regarding these matters that CVPS and the DPS cannot agree upon, CVPS shall promptly bring these issues to the Board for resolution. This docket shall remain open for purposes of resolving any such issues.

3. CVPS shall issue a contract for the review either within 45 days following the receipt of proposals, or within 10 days after resolution by the Board, if necessary, of any issues concerning the proposals, whichever is later. Upon execution of the contract by the management consultants, CVPS shall advise the DPS and the Board as to the expected completion date for the final report documenting the comprehensive review.

4. CVPS shall file with the Board as a compliance filing in this docket a copy of the final report produced by the management consultants who perform the comprehensive review ordered herein. The DPS shall have an opportunity to file comments with the Board within 30 days of the date CVPS makes this compliance filing.

5. CVPS's 2010 non-power-cost cap shall be increased by 2.25 "average" employees. In its 2010 base rate filing, CVPS shall separately identify the dollar amount added to its non-power-cost cap as a result of this Order.

Dated at Montpelier, Vermont, this 20th day of August, 2009.

s/James Volz	)	
	)	PUBLIC SERVICE
	)	
s/David C. Coen	)	BOARD
	)	
	)	OF VERMONT
s/John D. Burke	)	

OFFICE OF THE CLERK

FILED: August 20, 2009

ATTEST: s/Susan M. Hudson
Clerk of the Board

NOTICE TO READERS: This decision is subject to revision of technical errors. Readers are requested to notify the Clerk of the Board (by e-mail, telephone, or in writing) of any apparent errors, in order that any necessary corrections may be made. (E-mail address: psb.clerk@state.vt.us)

Appeal of this decision to the Supreme Court of Vermont must be filed with the Clerk of the Board within thirty days. Appeal will not stay the effect of this Order, absent further Order by this Board or appropriate action by the Supreme Court of Vermont. Motions for reconsideration or stay, if any, must be filed with the Clerk of the Board within ten days of the date of this decision and order.

ILLINOIS

Re N. Shore Gas Co., Docket No. 07-0241, ILLINOIS COMMERCE COMMISSION, Order (Feb. 5, 2008).

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	:	
	:	**07-0241**
Proposed general increase in natural gas rates. (tariffs filed March 9, 2007)	:	
	:	
The Peoples Gas Light and Coke Company	:	**07-0242**
	:	
Proposed general increase in natural gas rates. (tariffs filed on March 9, 2007)	:	**Cons.**

ORDER

February 5, 2008

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The Peoples Gas Light and Coke Company	:	**07-0242**
	:	
Proposed general increase in natural gas rates. (tariffs filed on March 9, 2007)	:	**Cons.**

ORDER

By the Commission:

PROCEDURAL HISTORY

On March 9, 2007, North Shore Gas Company ("North Shore" or "NS") filed with the Illinois Commerce Commission ("Commission"), and pursuant to Section 9-201 of the Public Utilities Act (the "Act")[1], the following tariff sheets: ILL. C.C. No. 17, Original Title Sheet (cancelling ILL. C.C. No. 16 in its entirety) and ILL. C.C. No. 17, Original Sheet Nos. 1 through 130. This tariff filing embodied a proposed general increase in gas service rates, three new "tracker" Riders, and revisions of other terms and conditions of service. The tariff filing was accompanied by direct testimony, other exhibits, and other materials required under Parts 285 and 286 of Title 83 of the Illinois Administrative Code (the "Code"), 83 Ill. Admin. Code Parts 285 and 286.

On March 9, 2007, The Peoples Gas Light and Coke Company ("Peoples Gas" or "PGL") filed with the Commission, and pursuant to Section 9-201 of the Act, the following tariff sheets: ILL. C.C. No. 28, Original Title Sheet (cancelling ILL. C.C. No. 27 in its entirety) and ILL. C.C. No. 28, Original Sheet Nos. 1 through 143. This tariff filing embodied a proposed general increase in gas service rates, four new "tracker" Riders, and revisions of other terms and conditions of service. The tariff filing was accompanied by direct testimony, other exhibits, and other materials required under Parts 285 and 286.

Notice of the proposed tariff changes reflected in this rate filing was posted in North Shore's and Peoples Gas' (the "Utilities" or "Companies") business offices and published in secular newspapers of general circulation in the Utilities' respective service

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[1] 220 ILCS 5/9-201.

areas, as evidenced by publishers' certificates, in accordance with the requirements of Section 9-201(a) of the Act and the provisions of 83 Ill. Admin. Code Part 255.

The Commission issued Suspension Orders as to North Shore's tariff filing on April 4, 2007, that suspended the tariffs to and including August 5, 2007, and further initiated Docket 07-0241. On July 25, 2007, the Commission issued a Resuspension Order, that suspended these tariffs to, and including, February 5, 2008.

The Commission issued Suspension Orders as to Peoples Gas' tariff filings on April 4, 2007, that suspended the tariffs to and including August 5, 2007, and initiated Docket 07-0242. On July 25, 2007, the Commission issued a Resuspension Order, that suspended these tariffs to, and including, February 5, 2008.

On April 23, 2007, Staff of the Commission ("Staff") filed a motion to consolidate Dockets 07-0241 and 07-0242, pursuant to 83 Ill. Admin. Code §200.600.

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 the two Dockets before duly authorized Administrative Law Judges ("ALJs") of the Commission, at its offices in Chicago, Illinois, on April 25, 2007, and April 27, 2007. More than ten days prior to April 25, 2007, notice of this status hearing had been provided by the Chief Clerk of the Commission to municipalities in the Utilities' service areas, in accordance with the requirements of Section 10-108 of the Act[2]. On April 25, 2007, at the status hearing, after addressing certain aspects of how consolidation would affect the conduct of these cases, the ALJs granted Staff's motion to consolidate.

Petitions to Intervene.

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"); the Citizens Utility Board ("CUB"); the City of Chicago (the "City") (collectively, CUB and the City are "CUB-City" or "City-CUB", their having used both terms in different filings) (collectively, the AG, CUB, and the City are "GCI" for "Governmental and Consumer Intervenors"); Constellation NewEnergy-Gas Division, LLC ("CNEG"); the Environmental Law and Policy Center ("ELPC"); the Illinois Industrial Energy Consumers ("IIEC"); Multiut Corporation ("Multiut"); Local Union No. 18007, United Workers Union of America, AFL-CIO (the "Local" or "UWUA"); Prairie Point Energy, LLC, d/b/a Nicor Advanced Energy, LLC ("NAE"); Retail Gas Suppliers ("RGS") an ad hoc group comprised of Dominion Retail Incorporated; Interstate Gas Supply; and U.S. Energy Savings Corporation; and Vanguard Energy Services, LLC ("Vanguard") (collectively, all of the foregoing parties are the "Intervenors").

Pre-Hearing Testimony.

On March 9, 2007, the Utilities filed their respective direct testimony together with their respective Part 285 filings. On June 5, 2007, Peoples Gas filed errata to its direct testimony and Part 285 submission.

[2] 220 ILCS 5/10-108.

On June 29, 2007, Staff and the Intervenors filed their respective direct testimony, except that Mr. Mierzwa did not submit direct testimony. RGS filed its direct testimony on July 2, 2007, and GCI filed their direct testimony on July 3, 2007.

On July 27, 2007, the Utilities filed the rebuttal testimonies of their witnesses.

On August 21, 2007, Staff and the Intervenors filed their respective rebuttal testimony, except that of Staff witness Rearden. On August 22, 2007 Staff moved for leave to file the rebuttal testimony of Staff witness Rearden *instanter*. On August 23, 2007, the ALJs issued a ruling granting Staff's Motion for Leave to File Rebuttal Testimony of Staff Witness David Rearden, *Instanter*.

On July 30, 2007, the ALJs granted Staff's Motion for Leave to File Supplemental Direct Testimony Instanter for its witness Kahle. On August 10, 2007, the Utilities filed supplemental rebuttal testimony of Mr. Fiorella to the supplemental direct testimony of Mr. Kahle.

On September 5, 2007 the Utilities filed the surrebuttal testimonies of their witnesses. On September 7, 2007, the Utilities filed a Second Errata, identifying corrections to attachments to their witness Amen's direct testimony. On September 10, 2007, the Utilities filed a Third Errata, identifying corrections to an attachment to the surrebuttal testimony of their witness Mr. Zack and deleting certain inadvertently repeated lines in the direct testimony of their witness Grace. And, on September 11, 2007, North Shore and Peoples Gas filed a Fourth Errata containing two corrections to its witness Ms. Grace's direct testimony and deleting a cross-reference in their witness Mr. Schott's surrebuttal testimony.

The Evidentiary Hearing.

The evidentiary hearing was held on September 10, 2007 through September 12, 2007, September 14, 2007, and September 17, 2007 at the offices of the Commission in Chicago, Illinois. At the evidentiary hearings, the Utilities, Staff, and the Intervenors, entered appearances and presented testimony. The following witnesses testified on behalf of the Utilities: Michael J. Adams, Director, Navigant Consulting, Inc.; Ronald J. Amen, Director, Navigant Consulting, Inc.; Lawrence T. Borgard, President and Chief Operating Officer, The Integrys Gas Group, and Vice Chairman of the Board and Chief Executive Officer, Peoples Gas and North Shore; Edward Doerk, Vice President, Gas Operations, Peoples Gas and North Shore; Russell A. Feingold, Managing Director, Navigant Consulting, Inc.; Salvatore Fiorella, Manager, State Regulatory Affairs, Peoples Gas (he retired from this position during these proceedings); Valerie H. Grace, Manager, Rates Department, Peoples Gas, and, subsequently, Manager, Regulatory Affairs; James C. Hoover, Director, Compensation, Integrys; Bradley A. Johnson, Treasurer, North Shore; Linda M. Kallas, Vice President, Financial Accounting Services, Peoples Gas; Brian M. Marozas, Coordinator, Trading Risk Management Department, Peoples Gas; Paul R. Moul, Managing Consultant, P. Moul & Associates; Joseph P. Phillips, Vice President, Information Technology, Integrys Business Support; Thomas L. Puracchio, Gas Storage Manager, Peoples Gas; Ilze Rukis, Manager, Alternative Resources, Wisconsin Public Service Corporation; James F. Schott, Vice President, Regulatory Affairs, Integrys Energy Group, Inc. and Peoples Gas; Eugene S. Takle, Professor of Atmospheric Science and Agricultural Meteorology, Co-director, Regional Climate Modeling Laboratory, Iowa State University; Frank L. Volante, Operations Manager, North Shore; Thomas E. Zack, Vice President, Gas Supply, Integrys.

The following witnesses testified on behalf of Staff: Dennis L. Anderson, Senior Energy Engineer, Engineering Department, Energy Division; Janis Freetly, Senior Financial Analyst, Finance Department, Financial Analysis Division; Thomas L. Griffin, Accountant, Accounting Department, Financial Analysis Division; Cheri L. Harden, Rate Analyst, Rates Department, Financial Analysis Division; Dianna Hathhorn, Accountant, Accounting Department, Financial Analysis Division; Daniel G. Kahle, Accountant, Accounting Department, Financial Analysis Division; Sheena Kight-Garlisch, Senior Financial Analyst, Finance Department, Financial Analysis Division; Peter Lazare, Senior Economic Analyst, Rates Department, Financial Analysis Division; Eric Lounsberry, Supervisor, Gas Section, Engineering Department, Energy Division; Mike Luth, Analyst, Rates Department, Financial Analysis Division; Bonita A. Pearce, Accountant, Accounting Department, Financial Analysis Division; Dr. David Rearden, Senior Economist, Policy Program, Energy Division.

GCI's witnesses were Michael L. Brosch, Principal, Utilitech, Inc.; David J. Effron, Consultant; William L. Glahn, Principal and Owner, Piedmont Consulting, Inc., except that the City did not sponsor certain specified testimony of Mr. Brosch.

CUB-City's witnesses were Christopher C. Thomas, Director of Policy, CUB; Jerome D. Mierzwa, Principal and Vice President, Exeter Associates, Inc.

NAE's witness was Lisa Pishevar, General Manager, NAE.

CNEG's witnesses were John M. Oroni, Regional Sales Director, CNEG; and Lisa A. Rozumialski, Manager of Gas Operations, CNEG.

ELPC's witness was Charles Kubert, Senior Environmental Business Specialist, ELPC.

IIEC, VES and CNEG jointly sponsored the testimony of Dr. Alan Rosenberg, Consultant, Brubaker & Associates.

Multiut's witnesses were Nachshon Draiman, President, Multiut; Raquel Lavenda, Manager of Operations, Multiut.

RGS' witness was James L. Crist, President, Lumen Group

VES' witness was Neil Anderson, Partner, VES.

UWUA's witness was James Gennett, President, Local Union No. 18007.

All parties were given the opportunity to cross-examine witnesses.

During the evidentiary hearing, various witnesses on behalf of Staff and various parties submitted oral errata to their pre-filed testimony, as reflected in the transcripts. On September 20, 2007, the ALJs directed that Staff and the parties file revised versions of the affected pre-filed testimony reflecting the oral errata presented at the evidentiary hearing. Staff and the parties subsequently complied in these respects.

Certain additional materials were received into the record thereafter by order of the ALJs. On November 26 2007, the ALJs marked the record “Heard and Taken”.

Rulings on Motions

On April 27, 2007, a Notice of Administrative Law Judges’ Ruling established the procedural schedule for these now-consolidated Dockets. Thereafter, on May 9, 2007, the ALJs issued an Order for a Case Management Plan and Schedule in these dockets. Also on May 9, 2007, and after considering all of the parties’ arguments, the ALJs entered a Protective Order for these Dockets

On August 13, 2007 the ALJs issued a ruling amending the case management order and confirming the date and time for the evidentiary hearing.

On September 5, 2007, the ALJs granted in part, and denied in part, the Utilities’ Motion to strike portions of GCI witness Glahn's direct and rebuttal testimonies.

On September 17, 2007, the ALJs granted the AG’s motion to strike a portion of the surrebuttal testimony of Mr. Schott. On September 18, 2007, Peoples Gas submitted its Second Revised surrebuttal testimony of Mr. Schott, reflecting the ALJs’ ruling on the related motion to strike.

On September 25, 2007, the ALJs issued a ruling approving the Proposed Stipulation entered into by Peoples Gas, North Shore, CUB and City with respect to the testimony of Ms. Kallas.

On September 18, 2007, NAE filed a Motion to Correct Transcript. On September 27, 2007, UWUA filed a Motion to Correct Transcripts. On October 11, 2007, Staff filed a First Motion to Correct Transcripts. On October 15, 16, 17, 18, 19, and 22, 2007, the Utilities filed motions to correct the transcripts.

On December 26, 2007, the ALJs granted the various motions to correct the transcripts.

Post-Hearing Briefs.

On October 12, 2007, the Utilities, Staff, the AG, CUB, the City, ELPC, IIEC, Multiut, NAE, RGS, VES, and UWUA each filed an Initial Brief (“Init. Br.”).Thereafter, on October 16, 2007, the Utilities filed a motion to correct their Initial Brief (to remove a superfluous paragraph). Also on October 16, 2007, Staff filed a Corrected Initial Brief (to correct the Appendices thereto).

On October 23, 2007, the Utilities, the AG, RGS, VES, City, CUB-City, ELPC, CUB, NAE, UWUA, IIEC, G, and Multiut each filed a Reply Brief (“Rep. Br.”). Staff filed its Reply Brief on October 24, 2007. Also, on October 23, 2007, the Utilities submitted a draft Proposed Order.

On November 26, 2007, the ALJs issued their Proposed Order. On December 14, 2007, Briefs on Exceptions (“BOE”) were filed by the Utilities, Staff, the AG, CUB, the City, ELPC, IIEC, Multiut, NAE, RGS, VES, and UWUA

On December 21, 2007, each of these same parties filed a Reply Brief on Exceptions (“RBOE”).

This Order considers all of the positions and arguments set out in the exceptions briefs listed above.

I. INTRODUCTION

A. Summary of Standards

The Commission, in these proceedings, is presented with the Utilities' first general rate cases since 1995. In addressing the issues raised in these consolidated Dockets, and in our consideration of the extensive evidentiary record, the Commission is governed by a number of basic legal principles.

In contested rate case proceedings the Commission must establish rates that are just and reasonable, with the burden of proof on the utility to establish the justness and reasonableness of a proposed rate. 220 ILCS 5/9-201(c); Business and Professional People for the Public Interest v. Illinois Commerce Comm'n., 146 Ill. 2d 175, 208 (1991). The Act requires the Commission to establish rates which are just and reasonable for both the investors and the consumers. Citizens Utility Board v. Illinois Commerce Comm'n., 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995).

While many of the presented issues are now uncontested, due to compromises among the parties, many disputed issues remain. Those disputes include the four new "tracker" Riders proposed by Peoples Gas and the three proposed by North Shore. The Commission will consider all of the uncontested and contested issues presented. We are mindful that all rulings and directives contained in this final Order must be within our jurisdiction, lawful and based exclusively on record evidence. 220 ILCS 5/10-103, 10-201(e)(iv); Business and Professional People for the Public Interest v. Illinois Commerce Comm'n, 136 Ill. 2d 192, 201, 227 (1989).

B. Nature of Operations

1. Peoples Gas

Peoples Gas is a local distribution company engaged in the business of transporting, purchasing, storing, distributing, and selling natural gas at retail to approximately 840,000 residential, commercial, and industrial customers within the City of Chicago. Peoples Gas Ex. LTB-1.0 at 4-5; Peoples Gas Ex. ED-1.0 at 3. This service territory covers an area of about 228 square miles and has a population of approximately three million people. Peoples Gas Ex. LTB-1.0 at 5. Peoples Gas employs approximately 1,540 people, virtually all within the City of Chicago. *Id.* at 5. Peoples Gas is a wholly owned subsidiary of Peoples Energy Corporation, which in turn is a wholly owned subsidiary of Integrys Energy Group, Inc. ("Integrys"). *Id.* at 5.

Peoples Gas' distribution system consists of approximately 4,025 miles of gas distribution mains. Peoples Gas Ex. ED-1.0 at 3. It owns approximately 425 miles of gas transmission lines. *Id.* The distribution system is most commonly operated at a pressure range of 0.25 to 25 pounds per square inch, while the transmission system operates at pressures up to 300 pounds per square inch or more. *Id.* Peoples Gas also owns a storage field, Manlove Field. *Id.*

The physical configuration of Peoples Gas' system is a dispersed/multiple city gate, integrated transmission/distribution and multi pressure-backed system. Id. It is designed to provide gas service to all customers entitled to be attached to the system, to deliver volumes of natural gas to all sales and transportation customers, and to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day. Id. at 4. A gas utility system sized only to accommodate average gas demands would not be able to meet system peak demands. Id. at 4.

2. North Shore

North Shore is a local distribution company engaged in the business of transporting, purchasing, storing, distributing and selling natural gas at retail to approximately 158,000 residential, commercial, and industrial customers within fifty-four communities in Lake and Cook Counties, Illinois. NS Ex. LTB-1.0 at 4; NS Ex. ED-1.0 at 3. North Shore employs approximately 200 people, while sharing many administrative facilities owned by Peoples Gas. North Shore Ex. LTB-1.0 at 4. North Shore is a wholly owned subsidiary of Peoples Energy Corporation, which in turn is a wholly owned subsidiary of Integrys. Id. at 5.

North Shore's distribution system consists of approximately 2,270 miles of gas distribution mains. North Shore Ex. ED-1.0 at 3. North Shore owns approximately 95 miles of gas transmission lines. Id. Its distribution system is most commonly operated at a pressure of 45 pounds per square inch, while the transmission system operates at a pressure of 250 pounds per square inch. Id. While North Shore does not own any storage fields, it does purchase storage services from Peoples Gas, pursuant to a storage services agreement, approved by the Commission, and from two interstate pipelines. Id. In addition, North Shore owns a liquid propane production facility used for peaking purposes. Id.

The physical configuration of North Shore's system is a dispersed/multiple city-gate, integrated transmission/distribution and multi pressure-based system. Id. It is designed to provide gas service to all customers entitled to be attached to the system, to deliver volumes of natural gas to all sales and transportation customers, and to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day. Id. at 4. A gas utility system sized only to accommodate average gas demands would not be able to meet system peak demands. Id.

C. Test Year

The Utilities each proposed their fiscal year 2006, i.e., the twelve months ending September 30, 2006, as their test year. Fiorella Dir., PGL-NS Ex. SF-1.0 at 5. The 2006 test year data were based on the Utilities' actual 2006 revenues, expenses, and rate base items, subject to appropriate adjustments. Id. at 6-7. No party contested the proposed test year, which was ordered by the Commission In re WPS Resources Corp., et al., Docket 06-0540, Appendix A, Condition of Approval No. 13 (Order Feb. 7, 2007).

II. RATE BASE

A. Overview

1. Peoples Gas

In its direct case, Peoples Gas proposed a rate base of $1,308,007,000, consisting of $1,500,600,000 of net plant ($2,434,914,000 of gross plant less $934,314,000 of Accumulated Provision for Depreciation and Amortization ("Depreciation Reserve"), plus $126,359,000 for three items increasing rate base, less $318,952,000 for items reducing rate base. *E.g.*, PGL Ex. SF-1.1 at Sched. B-1.

In the course of testimony, Peoples Gas either agreed with, or, in order to narrow the issues, accepted a number of rate base adjustments proposed by Staff and the GCI, resulting in a final rate base figure of $1,289,531,000. This figure consists of:

- $1,495,173,000 of net plant ($2,429,392,000 of Gross Utility Plant less $934,219,000 of Accumulated Provision for Depreciation and Amortization or "Depreciation Reserve");
- $126,359,000 for three additional items, i.e., Gas in Storage, Materials and Supplies, and Cash Working Capital; and
- $332,001,000 for reductions, mainly Accumulated Deferred Income Taxes. E.g., NS-PGL Ex. SF-4.1P.

The uncontested and contested issues relating to Peoples Gas rate base are being assessed in the following Sections (B) through (F) of this Part II of the Order.

2. North Shore

In its direct case, North Shore proposed a rate base of $197,107,000, consisting of $231,444,000 of net plant ($380,087,000 of gross plant less $148,643,000 of Depreciation Reserve), plus $10,922,000 for three items increasing rate base, less $45,259,000 for items reducing rate base. E.g., NS Ex. SF-1.1 at Sched. B-1.

In the course of further testimony, North Shore also agreed with, or for purposes of narrowing the issues, accepted a number of rate base adjustments proposed by Staff and GCI, that resulted in North Shore's final rate base figure of $193,577,000. That figure consists of:

- $229,779,000 of net plant ($378,350,000 of gross plant less $148,571,000 of Depreciation Reserve);
- $10,922,000 for three additional items, i.e., Gas in Storage, Materials and Supplies, and Cash Working Capital; and
- $47,124,000 for reductions, mainly Accumulated Deferred Income Taxes. *E.g.*, NS-PGL Ex. SF-4.1N.

The uncontested and contested issues relating to its rate base are discussed in the following Sections (B) through (F) of this Part II of the Order.

B. Uncontested Issues

1. Original Cost Determination as to Plant Balances as of 9/30/06

a) The Record

Staff and the Utilities agree as to the original cost findings regarding the Utilities' plant as of the end of the fiscal year 2006 (September 30, 2006). Staff recommended that the $2,327,990,000 original cost for Peoples Gas and the $369,442,000 original cost for North Shore of plant at September 30, 2006, reflected on the Utilities' Schedules B-1, Line 1, Column D, be unconditionally approved as the original cost of plant. In their surrebuttal testimony, the Utilities accepted Mr. Kahle's recommendation. NS-PGL Ex. LMK-3.0 at 5-6. Given Staff's recommendation regarding the original cost determination, Staff recommends the Commission's order state:

> It is further ordered that the $2,327,990,000 original cost for Peoples Gas and the $369,442,000 original cost for North Shore of plant at September 30, 2006, reflected on the Utilities Schedules B-1, Line 1, Column D, is unconditionally approved as the original cost of plant.

Staff Ex. 15.0 Corrected at 21-22.

b) Commission Analysis and Conclusion.

We accept Staff's recommendation to have the final order include an original cost determination pursuant to 83 Ill. Adm. Code 510 and Appendix A thereto, as follows:

> It is further ordered that the $2,327,999,000 original cost for Peoples Gas and the $369,442,000 original cost for North Shore of plant at September 30, 2006, as reflected on the Utilities' Schedules B-1, Line 1, column D, is unconditionally approved as the original cost of plant.

The Commission finds that this proposed language is reasonable, appropriate and agreed on. Therefore, it is approved.

2. *Pro Forma* Capital Additions

a) The Record

Peoples Gas and North Shore originally proposed *pro forma* adjustments, for post-test year capital additions reasonably expected to be placed in service no later than February 2008, in the gross amounts of $104,524,000 (net $95,464,000 after the applicable subtractions for Depreciation Reserve and ADIT) and $10,645,000 (net $9,899,000 after the applicable subtractions for Depreciation Reserve and ADIT), respectively. *E.g.*, PGL Ex. SF-1.0 at 18-19; PGL Ex. SF-1.1, Scheds. B-1, column [E], B-2, column [B], and B-2.1; NS Ex. SF-1.0 at 17-18; NS Ex. SF-1.1, Scheds. B-1, column [E], B-2, column [B], and B-2.1.

In his corrected rebuttal testimony, Staff witness Kahle proposed adjustments to the *pro forma* plant additions the Utilities had included in rate base. Mr. Kahle recommended the removal of costs which were only based upon 2007 capital budget additions. Mr. Kahle found those budgeted costs to not be known and measurable in accordance with 83 Ill. Adm. Code 287.40. Staff Ex. 15.0, Schedules 15.2 N and P Corrected. As Mr. Kahle testified, the mere adoption of a budget is not evidence that a project is reasonably certain to occur as is required by Section 287.40. Staff Ex. 15.0 Corrected, at 15. After reviewing the Utilities' response to a data request, Mr. Kahle did allow *pro forma* capital additions that were supported by ten months of actual expenditures and two months of estimated expenditures. He found those amounts to be known and measurable.

In their surrebuttal testimony, the Utilities accepted Mr. Kahle's adjustments after Mr. Kahle in a data request response recognized and accepted Peoples Gas' cushion gas additions in the amount of $10.405 million. NS-PGL Ex. SF-4.0, at 5-6. Staff and the Utilities also agree on Staff's adjustment to Depreciation Expense. In his rebuttal testimony, Staff witness Kahle proposed adjustments to depreciation expense, the reserve for depreciation, and accumulated deferred income taxes related to the adjustments to pro forma plant additions. Staff Ex. 15.0, Schedules 15.2 N and P Corrected. In their surrebuttal testimony, the Utilities accepted Mr. Kahle's adjustments. NS-PGL Ex. SF-4.0 at 5-6.

The Utilities explain that they do not contest Staff's final revised figures for *pro forma* adjustments for capital additions, which consist of the amounts Staff's witness suggested in his rebuttal testimony (a reduction of $19,232,000 for Peoples Gas and $1,734,000 for North Shore (gross amounts)) plus an additional $10,405,000 of Peoples Gas' cushion gas additions he supported in a subsequent data request response (in evidence), i.e., a net $95,697,000 ($104,524,000 less $19,232,000 plus $10,405,000) as to Peoples Gas and a net $8,911,000 ($10,645,000 less $1,734,000) as to North Shore. Kahle Corr. Reb., Staff Ex. 15.0 at 14-16; NS-PGL Ex. SF-4.0 at 5-6; NS-PGL Ex. SF-4.2P, column [D]; NS-PGL Ex. SF-4.2N, column [D].

b) Commission Analysis and Conclusion

The Commission finds the Staff final revised proposal that the Utilities' *pro forma* adjustments for capital additions be a net $95,697,000 as to Peoples Gas and a net $8,911,000 as to North Shore to be unopposed by any party, reasonable and appropriate. Therefore, each of these amounts is approved.

3. Capitalized Lobbying Expenses

See Section III (B)(5)(d) of this Order, infra.

4. Capitalized City of Chicago Resurfacing Costs (PGL)

See Section III (B)(2)(c) of this Order, infra.

5. ADIT - Gas Cost Reconciliation

a) The Record

North Shore and Peoples Gas do not contest GCI's proposed adjustments to ADIT related to gas cost reconciliation. NS-PGL Ex. SF-2.0, 4:82-90, 5:109; PGL Ex. SF-2.2P, column [E]; NS Ex. SF-2.2N, column [D]. The proposed adjustments increase ADIT, and thus reduce rate base, by the amounts of $5,748,000 as to Peoples Gas and $1,142,000 as to North Shore. GCI Ex. 2.0 at 14,16-17 and Sched. B-2.

b) Commission Analysis and Conclusion

The Commission finds that GCI's proposed adjustments to ADIT related to gas cost reconciliation as revised, which reduce Peoples Gas' rate base by $5,748,000 and North Shore's rate base by $1,142,000, are uncontested and reasonable. Therefore, these adjustments are each approved.

6. [ADIT] AMT - Gas Charge Settlement

a) The Record

The Utilities do not contest GCI's proposed adjustments to Alternative Minimum Taxes ("AMT"), and thus to ADIT. NS-PGL Ex. SF-2.0 at 4-5; PGL Ex. SF-2.2P, column [F]; NS Ex. SF-2.2N, column [E]. GCI witness Effron's proposed adjustments to AMT, and thus to ADIT, which are related to the gas charge settlement, increase ADIT, and thus reduce rate base, by $7,820,000 as to Peoples Gas and $773,000 as to North Shore. GCI Ex. 2.0 at 14-16 and Sched. B-2.

b) Commission Analysis and Conclusion

The Commission finds that GCI's proposed adjustments to Alternative Minimum Taxes, as revised, which increase ADIT and thus reduce Peoples Gas' rate base by $7,820,000 and increase ADIT and thus reduce North Shore's rate base by $773,000, are uncontested and reasonable. Therefore, these adjustments are approved in the amounts stated.

C. Plant

1. Capitalized Incentive Compensation

See Section III(C)(3)(b) of this Order, below.

2. Hub Services (PGL)

See Section V of this Order, below.

D. Reserve for Accumulated Depreciation and Amortization

1. GCI's Proposed Adjustments

a) North Shore and Peoples Gas

Peoples Gas and North Shore maintain that they each have correctly calculated the amounts for the Depreciation Reserves that are subtracted from gross plant when calculating their rate bases. In so doing, they started with the Depreciation Reserve amounts as of the end of the test year, fiscal year 2006, i.e., as of September 30, 2006, and then made the adjustments needed to reflect the impacts of their proposed adjustments to plant, including their *pro forma* adjustments for post-test year capital additions. PGL Ex. SF-1.0 at 9, 14-15 & 18; PGL Ex. SF-1.1, Sched. B-1, line 2, Sched. B-2, column [B], Sched. B-2.1, Sched. B-6; NS Ex. SF-1.0, at 9, 14-15 & 17- 18; NS Ex. SF-1.1, Sched. B-1, line 2, Sched. B-2, column [B], Sched. B-2.1, Sched. B-6.

b) Staff

Staff did not address this issue in its Initial Brief. On Reply Brief, however, Staff stated that:

> After further evaluating the positions advanced by the various parties in testimony and briefs, Staff withdraws its objections to Mr. Effron's adjustment. In particular, Staff no longer supports the position that Mr. Effron's adjustment violates 83 Ill. Adm. Code Section 287.40. The impact on the rate base of Peoples Gas is to increase the accumulated depreciation reserve $43,134,000 (GCI Ex. 5.1, Schedule B-1 Revised) and deferred income taxes $587,000 (GCI Ex. 5.1, Schedule B – 2 Revised). The impact on the rate base of North Shore Gas is to increase the accumulated depreciation reserve $5,721,000 (GCI Ex. 5.2, Schedule B-1 Revised) and deferred income taxes $15,000 (GCI Ex. 5.2, Schedule B – 2 Revised).

c) GCI Parties

(Both the AG and the City-CUB take similar positions on the issue).

The GCI point out that both Peoples Gas and North Shore proposed adjustments to rate base in order to recognize plant additions through September 30, 2007, or one year after the end of the test year. PGL Ex. SF-1.0 at 18, 19; NS Ex. SF-1.0 at 17. While the Utilities recognize the increase in accumulated depreciation directly related to the forecasted plant additions, the GCI observe that they do not recognize the growth in accumulated depreciation on embedded plant-in-service that will be taking place as the new plant additions are going into service. Id*.*

GCI witness Effron explained that, as future plant additions take place and increase the balance of gross plant, the accumulated reserve for depreciation will also continue to grow as a result of recording depreciation expense on total plant-in-service. Thus, the net plant-in-service included in rate base will not increase by an amount equal to future additions. According to Mr. Effron, when growth in the balance of the accumulated reserve for depreciation is taken into account, as it should be, the effect of growth in rate base due to plant additions is mitigated significantly. Id*.* at 7-8.

The GCI contend that the Utilities have failed to consider and include this necessary offset to the revenue requirement effect of the post-test year additions to plant. The record shows, they argue, that in the 12 months ended September 30, 2006, Peoples recorded $48,664,000 of depreciation and amortization expense on its jurisdictional plant-in-service. Id*.* Further, from September 30, 2006 to September 30, 2007 (the period covered by the proposed additions to plant) the balance of accumulated depreciation and amortization can be expected to increase by more than $48 million as a result of recording depreciation expense on plant that was in service during the test year. GCI Ex. 2.0 at 6. Because the accumulated reserve for depreciation is deducted from plant in service in the determination of rate base, this increase in the depreciation reserve will reduce rate base by more than $48 million, and consequently reduce the revenue requirement. GCI witness Effron noted that while the amounts are proportionally smaller for North Shore, the principle is the same: The growth in the accumulated reserve for depreciation will provide a substantial offset to the growth in rate base resulting from plant additions. Id. at 7.

The AG notes the Utilities to assert that the cases relied on by Mr. Effron in testimony fail to support his proposed adjustment for accumulated depreciation. PGL-NS Ex. SF-4.0 at 8. In particular, the Utilities claim that the Orders in CILCO, Docket No. 02-0837, and AmerenCIPS and AmerenUE, Docket Nos. 02-0798, 03-0008 & 03-0009 (consol.), are not relevant to this proceeding based on the facts and circumstances for reason that "those cases pertained to utilities which had no increase in net plant." Id. The GCI argue, however, that these are only two of the cases that Mr. Effron considered.

For their part, the GCI refer the Commission to the Illinois Power case, Docket No. 01-0432, and AmerenCIPS and AmerenUE. In both matters, GCI observe, plant-in-service was growing but, as is the case in this docket with Peoples Gas and North Shore, such growth was found to be offset by growth in the reserve for depreciation. For example, they note, in AmerenCIPS and AmerenUE the Commission found "that UE's proposed additions to plant-in-service should be included in rate base" only "to the extent that they exceed increased accumulated depreciation." Docket Nos. 02-0798, 03-0008 & 03-0009 (consol.), Order (October 22, 2003). The Commission further concluded that this balanced treatment of plant additions and accumulated depreciation more accurately matches the costs and revenues that may be expected for the period during which the rates are in place. Id.

The GCI further contend that a review of the Commission's decisions in the CILCO case and the AmerenCIPS and AmerenUE cases also support Mr. Effron's position that adjustments to include post-test year plant additions in rate base should be offset by the known and measurable growth in the balance of the accumulated reserve for depreciation that will occur as plant is being added. GCI observe the Utilities to claim that these cases involved circumstances when there was no increase in net plant over time. PGL-NS SF-4.0 at 8. In the GCI's view, however, the argument that the circumstances in these cases are irrelevant to the instant docket is, in effect, to argue that if there is no increase in net plant over time, then it is appropriate to recognize post test year growth in depreciation reserve, but if the net plant is growing by $1 per year, then it would be inappropriate to recognize post-test year growth in the depreciation reserve as an offset to post-test year plant additions. A reasonable reading of the Commission's decisions in these dockets, the GCI maintain, supports Mr. Effron's balanced adjustment to recognize post-test year growth in the Utilities' depreciation reserve.

GCI summarize that, to allow the Company to reflect adjustments to rate base for post-test year plant additions without recognizing the attendant growth in the accumulated reserve for depreciation will result in a mismatch of rate base items and a significant distortion of the Utilities' rate bases during the period of time rates set in this case will be in effect. Accordingly, they argue, North Shore's pro forma test year rate base should be reduced by $5,721,000. GCI Ex. 5.2, Schedule B. And, Peoples Gas' pro forma test year rate base should be reduced by $43,134,000 to recognize post-test year growth in the accumulated reserve for depreciation that will accompany the growth in plant-in-service from post-test year additions to plant-in-service. Id.

d) North Shore / Peoples Gas Response

The Utilities contend that the Commission should reject the adjustments to the Depreciation Reserves proposed by GCI witness Effron. GCI Ex. 2.0 at 5-12; GCI Ex. 5.0 at 3-6. Noting Mr. Effron to assert that his proposed adjustments somehow are justified by the Utilities' proposed *pro forma* adjustments for post-test year capital additions, the Utilities point out that he does not, and cannot, claim that the Utilities have incorrectly calculated the impacts of those adjustments on the Depreciation Reserves. Instead, Utilities argue, Mr. Effron inappropriately and incorrectly seeks to use those adjustments as an excuse to add another year of depreciation to the Depreciation Reserve related to existing plant as of the test year, and not to the depreciation applicable to the *pro forma* adjustments for post-test year capital additions for which the Utilities already correctly have accounted. NS-PGL Ex. SF-2.0 at 9-1; NS-PGL Ex. SF-4.0 at 8-9. Utilities note Staff's witness to agree that Mr. Effron's proposed adjustments are inappropriate and incorrect for that reason, *i.e*., the proposed adjustments switch test years for the Depreciation Reserve values for existing plant as of the test year. Staff Ex. 15.0.

The proposal also is unfair, Utilities assert, because it does not move forward to a 2007 value, rather than a test year value, other items which would increase the Utilities' revenue requirements. NS-PGL Ex. SF-2.0 at 10. Indeed, the Utilities contend, Mr. Effron's claim that the ADIT value likely would increase in 2007 and "there is no reason to believe that the other components [of rate base besides net plant and ADIT] would change materially from the test year to 2007", misses the point about inappropriately and unfairly deviating from test year principles. GCI Ex. 5.0 at 3-4.

Mr. Effron's proposed adjustment, the Utilities argue, should further be rejected for failure to meet the criteria for *pro forma* adjustments. According to the Utilities, it does not meet the "known and measurable" criteria of 83 Ill. Adm. Code § 287.40, as Staff's witness also pointed out. Staff Ex. 15.0 at 17. The Utilities maintain that the proposal is based on attrition, and contrary to the attrition and inflation language of 83 Ill. Adm. Code § 287.40, the same that Mr. Effron himself invoked when opposing the Utilities' proposed *pro forma* adjustments for inflation in non-payroll expenses, and which the Utilities later withdrew. GCI Ex. 2.0 at 26-27 (mistakenly citing the predecessor provision of 83 Ill. Adm. Code § 287.40 in Part 285 of the Commission's rules prior to the 2003 amendments).

The Utilities observe that the Commission rejected adjustments like those that Mr. Effron proposes In re Commonwealth Edison Co., Dkt. 05-0597; Order at 12-15, (July 26, 2006) and In re Commonwealth Edison Co., Dkt. 01-0423; Interim Order at 41-44 (April 1, 2002) (carried forward to final Order of March 28, 2003). While Mr. Effron would claim that his proposal finds support in other Commission orders, the Utilities assert that the facts of the instant proceeding are more like those of the two cases they rely on and not the ones that Mr. Effron cites to (where the utilities had no increase in net plant). *See also* NS-PGL Init. Br. at 20; NS-PGL Ex. SF-2.0 at 10; NS-PGL Ex. 4.0 at 8. To be sure, the Utilities argue, their circumstances here are not the same as those of the utilities in any of the cases cited to by the GCI. Peoples Gas' and North Shore's net plant in service balances, they assert, have not been decreasing over time, but have been increasing. According to the Utilities, the record, i.e., Schedules B-5 and B-6 in PGL Ex. SF-1.1 and NS Ex. SF-1.1 and Tr. 117-118, provides uncontradicted evidence of the Utilities' increasing net plant balances.

Peoples Gas and North Shore explain that they are using a historical test year. And, the Utilities maintain that they have provided supporting documentation to parties with respect to their *pro forma* adjustments for post-test year capital additions (amounts of approximately $96 million for Peoples Gas and $9 million for North Shore, reflecting the correct deductions for the Depreciation Reserves and ADIT). *E.g.*, NS-PGL Ex. SF-2.0 at 8-9; NS Ex. SF-1.1, Sched. B-2; PGL Ex. SF-1.1, Sched. B-2. As a result, the Utilities' *pro forma* adjustments for post-test year capital additions are uncontested. NS-PGL Init. Br. at 16-17. Yet, it seems to the Utilities that GCI would seek to use this as a pretext for their proposed adjustments to the Depreciation Reserves. The Utilities maintain that they correctly dispute the proposal of GCI witness Effron to add another year of depreciation to the Depreciation Reserves; a proposal that is applicable to existing plant, and not related to the plant involved in the *pro forma* adjustments. They note too, that Staff's witness agreed that Mr. Effron's proposed adjustments that, in effect, change the test year for existing plant, were inappropriate and incorrect

The Utilities emphasize that the decisions on point with the instant proceeding appear in Commonwealth Edison Co., Docket No. 05-0597, Order (July 26, 2006) and Commonwealth Edison Co., Docket No. 01-0423, Interim Order (April 1, 2002) (incorporated in final Order, March 28, 2003). Yet, they observe, these are decisions that the AG and City-CUB neglect to address in their Briefs. In those cases, the Utilities point out, the Commission rejected Mr. Effron's proposed adjustments to Depreciation Reserves that are virtually the same as he now proposes in this proceeding, and in situations that are factually similar to the situations of Peoples Gas and North Shore. According to the Utilities, the facts set out in the cases cited by the AG and City-CUB are much different.

In Docket 05-0597, Utilities point out, the AG unsuccessfully argued that decisions in the same IP, AmerenCIPS, AmerenCILCO, and AmerenUE cases, were relevant to the ComEd case. There ComEd argued, as do the Utilities here, that those cases factually were not on point. Order at 13-15, Docket No. 05-0597. The Commission agreed with ComEd and rejected the AG's proposed adjustment to the Depreciation Reserve, stating in relevant part that :

> 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. Order at 15, Docket 05-0597 (July 26, 2006).

No different here, Utilities argue, the GCI's proposed adjustments to the Depreciation Reserves do not correlate to any *pro forma* plant additions or to any plant adjustment proposed by any of the parties. Instead, and in a summary fashion, GCI's proposed adjustments take one part of rate base and move it into the future. Based on the foregoing, the Utilities contend that GCI's proposed adjustments to the Depreciation Reserve are not warranted, violate test year rate making principles, and are not appropriate under the *pro forma* adjustments rule, 83 Il Admin. Code § 287.40.

Further still, the Utilities would note that Mr. Effron's proposal miscalculates the Utilities' costs of removal, because it does not comport with how the Utilities account for these costs. According to the Utilities, he erroneously proposes to deduct amounts for costs of removal from the Depreciation Reserves when, instead, they should be added to depreciation expenses, and this would increase the revenue requirements. And, Utilities add that his figures are wrong. NS-PGL Ex. SF-2.0 at 11-12; NS-PGL Ex. SF-4.0 at 9-10 (also noting that the Commission has accepted the Utilities' accounting for costs of removal over several decades).

e) Commission Analysis and Conclusion

All parties agree that this issue has been previously addressed by the Commission. All parties largely agree that the facts differ from one case to another. All parties should agree that Commission action brings certainty to a situation and settles expectations. This is another way of saying that unless there are clear and distinguishable reasons for deciding a case differently, the Commission will follow in line with precedent. To do otherwise risks a charge of arbitrary and capricious action.

There is much debate as to which of the decided cases are most reflective of the instant situation. Having reviewed the evidence and the parties' arguments, we find that the facts at hand most closely resemble the situation that we most recently considered in Docket 05-0597 (that concerns Commonwealth Edison Company). In that proceeding, then AG witness Effron proposed to increase through the end of 2005, the entire depreciation pertaining to all plant that went into service prior to and in the 2004 test year. Order at 12, Docket 05-0597. The proposal of GCI witness Effron is essentially the same in this case.

Here, as in Docket 05-0597, the Utilities made depreciation adjustments for post-test year plant that comprises its pro forma additions. Here, as in Docket 05-0597, the Utilities argue that the proposed adjustment is one-sided and unfair. Here, as in Docket 05-0597, the Utilities argue that the proposal presented by the intervening party violates Section 287.40 and test year rate-making principles. Here, as in Docket 05-0597, the Utilities argue that the proposed adjustment merely takes one part of rate base and moves it one additional year into the future. Here, as in Docket 05-0597, the same Orders entered in earlier dockets are being asserted by the intervening parties in support of their position.

In our conclusion for Docket 05-0597 the Commission determined that the same cases that the GCI parties rely on here, were inapplicable and without merit. Order at 15, Docket 05-0597. We further agreed with the assertion (made in this proceeding) that the effect of the proposed adjustment would be to "inappropriately bring the test year into the future for accumulated depreciation. Id. We observed too, that the proposed adjustment does not correlate to any pro forma capital additions or any plant adjustment proposed by any party. In the end, the Commission rejected the AG's adjustment in Docket 05-0597.

In our view, and under our analysis, the outcome of the 05-0597 proceeding is controlling on the dispute at hand. Indeed, we are shown nothing as would have us depart from the decision that the Commission set out in that matter. Staff's changed position on Reply Brief is insufficient in these premises. For their part, the GCI take little or no account of the facts, circumstances or findings in Docket 05-0597. Consistent with our prior and controlling decision on the issue, and for the same reasons, we here reject the GCI's proposed adjustment. While Staff and the GCI take exception with our reliance on the disposition of this issue in the ComEd orders, they make no attempt to distinguish the facts in that proceeding from the facts at hand. Thus, we are unable to lawfully deviate from that conclusion. Moreover, Staff effectively admits that additional record analysis is needed to allow for consideration of the GCI's proposed adjustment. This (and the arguments that the Utilities set out in reply to the exceptions), convinces the Commission that, on the evidence presented, our decision is right.

2. Derivative Adjustments

Other than GCI's proposed adjustments to the Utilities' Depreciation Reserves, discussed in Section II (D)(1) of this Order, Staff and Intervenors have not proposed any independent adjustments to the Depreciation Reserves as such. Accordingly, the Commission, as to the Depreciation Reserves, need only make derivative calculations reflecting the approved adjustments to plant in rate base.

E. Cash Working Capital

Cash working capital ("CWC") is the amount of cash a company requires to finance its day-to-day operations. PGL-NS Ex. MJA-1.0 at 3. To understand why that amount of cash is included in rate base, where it earns a return for the utility, CWC can be conceptualized as a cash advance from investors. That is, insofar as the flow of cash in and out of the utility's coffers is imperfectly balanced, and the utility requires ready funds to pay expenses as they become due, investors finance the shortfall. To calculate whether such shortfall indeed exists, and to determine its size and duration (which vary over the course of a year) for ratemaking purposes, regulators and utilities employ recognized accounting principles and methodologies.

The principle method used is the lead-lag study. It focuses on expense leads (the time intervals between a utility's assumption of responsibility for various expenses (typically, when a product or service is received) and the actual payment of those expenses) and revenue lags (the time interval between acquiring the rights to revenues and the actual receipt of revenues). Approved categories of leads and lags are quantified, weighted, summed and compared. The difference is CWC (positive or negative[3]).

Disputes can arise with respect to the type of lead-lag study used and the identification and treatment of the expenses and revenues included. Initially, the Utilities calculated CWC using the *net* lag methodology[4]. Id. Subsequently, though, the Utilities acceded to Staff's preference for the *gross* lag methodology[5], stating that the two methodologies, when properly applied, produce essentially equivalent results. PGL-NS Ex. MJA-2.0 at 4.

However, the Utilities and Staff disagree regarding treatment of certain inputs for the gross lag analysis. First, Staff proposes to include capitalized payroll and payroll-related expenses in CWC calculations, and the Utilities object. Second, the Utilities would use pass-through taxes to calculate expense lead times, while Staff would not. Third, the Utilities would treat all Taxes Other Than Income Taxes alike, but Staff would split off real estate taxes for separate treatment. The Commission addresses each disputed issue in the following subsections of this Order.

Prior to service of the ALJ's Proposed Order, the Utilities' calculations yielded a CWC allowance of approximately $30.9 million for PGL and ($1.1 million) for North Shore. PGL-NS Ex's. MJA-1.1. Staff's adjustments would have decreased Peoples Gas's and North Shore's CWC allowances to, approximately, $16.6 million and ($1.7 million), respectively (assuming no other adjustments to the Utilities' requested revenues and identified expenses). Staff Init. Br., App. A, p. 8 & App. B, p. 9.

After service of the Proposed Order, the Utilities requested "correction" of what they perceived to be mathematical errors in the appendices attached to the Proposed Order, as well as inconsistencies between the text of the Proposed Order and the appendices[6]. The requested revisions would alter the Utilities' approved CWC and other elements in its revenue requirement calculations (as they appeared in the Proposed Order).

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[3] When CWC is negative, there is a surplus, rather than a shortfall, in day-to-day funds. A subtraction is made from rate base to account for negative CWC, as Staff and the Utilities propose here for North Shore. Staff Ex. 15.0 at 14.

[4] In a net lag study, all leads are added (in days), as are all lags. The totals are netted against each other, then the net revenue lag (if any) is divided by 365 days to determine a daily CWC factor. Adjusted yearly cash expenses are multiplied by that factor to quantify CWC (the amount of cash to include in rate base).

[5] In a gross lag study, the sum of revenue lags is divided by 365 days to establish a daily CWC factor, which is multiplied by the utility's adjusted test year revenues. (Adjustments remove non-cash items, such as depreciation and uncollectibles, that are unavailable to pay expenses.) Similarly, each category of expense lead is also divided by 365 days and the resulting CWC factor is multiplied by test year expenses. The revenue and expense working capital requirements are then summed to determine CWC for rate base.

[6] The Utilities first raised these issues in a motion, which was denied on procedural grounds, then restated the issues on exceptions.

In particular, the Utilities maintain that the appendices incorrectly included amounts for depreciation and amortization in CWC calculations. PGL-NS BOE at 7. Staff agrees that those amounts should be removed, to correct an inadvertent omission of the necessary deduction. Staff RBOE at 2. Staff proposes an approach for calculating the deductions, *id.*, at 3 and App's A & B, which we find reasonable and hereby approve.

Also on exceptions, Staff recommended a clarification of a mislabeled item in the Appendices to the Proposed Order. As Staff states, the item should be labeled "Operating Expenses." Staff BOE at 8.

1. Capitalized Payroll and Payroll-Related Expenses

Staff recommends that we include "capitalized payroll, pensions and benefits in the CWC requirement calculation because these items reflect cash outlays of the [Utilities'] normal day-to-day operations." Staff Init. Br. at 7. "[W]hen the company incurs a cost like payroll, cash is required regardless of whether the cost is expensed or capitalized." Id. Staff emphasizes that we approved the use of capitalized payroll for calculating CWC in the recent Ameren consolidated rate cases[7].

The Utilities respond that Staff is improperly injecting capitalized costs into a CWC calculation that should be limited to operating expenses, with the result that the Utilities' CWC requirements are understated. PGL-NS Ex. MJA-3.0 at 11. "Capital expenditures are not included in the analysis because such costs were considered elsewhere in rate base." Id. at 13. Furthermore, the Utilities argue, even if it were appropriate to use capitalized costs to compute CWC, there would have to be a corresponding revenue stream to cover those costs, but Staff has not included that revenue stream in its CWC analysis. Id. Moreover, the Utilities maintain, Staff "has selectively chosen which capitalized costs to include" in its CWC determination, while ignoring others that similarly entail cash outlays by the Utilities. Id.

Commission Analysis and Conclusion

In the Ameren rate cases, the Commission adopted Staff's recommendation that capitalized payroll costs be included in the CWC calculations. In doing so, we emphasized that Ameren had not included in rate base "any payroll costs going forward from the test year." Ameren, at 36. With the absence of capitalized payroll costs in rate base, Ameren would not realize recovery on such costs. Consequently, we were willing to include capitalized payroll costs in Ameren's CWC computation, both because there would be no double recovery on them (i.e., they would not appear in rate base twice) and because fulfilling payroll commitments was a day-to-day operational obligation of the utility. In these proceedings, however, the pertinent payroll costs appear to be accounted for in the Utilities' rate bases. Staff does not claim otherwise. It follows that the precedential rationale for including a *capitalized* cost in an analysis concerning *operational expenses* is missing.

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[7] AmerenCILCO, AmerenCIPS, and AmerenIP, Docket Nos. 06-0070, 06-0071 & 06-0072 (Cons.) ("Ameren"), Order November 21, 2006, at 36.

The question, then, is whether another rationale for Staff's position exists. Staff states that "[l]ike cash outlays for items that are expensed, capitalized items must also be paid." Staff Ex. 15.0 at 8. Moreover, Staff emphasizes, "they are paid with the same lead time" as capitalized payroll costs. Id. Restating Staff's proposition, because capitalized payroll items behave like expensed payroll items, they belong in the CWC calculation. The Commission does not agree. The relevant accounting rules and test year mechanics are clear – capitalized items enter rate base and operating expenses do not. PGL-NS Ex. 3.0 at 14. Perhaps the real essence of Staff's argument is that payroll-related costs should not be included in rate base at all (other than as part of the CWC calculation). If so, that argument is unexpressed and certainly undeveloped in this dispute. In any event, the fact that an item requires a cash outlay does not mean it belongs in the CWC determination. Virtually everything a utility purchases involves cash outlay, but the purchase is either capitalized or expensed, not both. Finally - and this point is not part of our decision-making on this issue - it is not apparent to the Commission how reducing CWC, while double-counting items in rate base, would reduce customers' bills.

On exceptions, Staff recommends an approach for removing capitalized payroll-related costs from previous CWC calculations in these dockets. Staff RBOE at 3-7 & App's. A & B. The Utilities also propose a method. PGL-NS BOE at 8-9 & Except's. 3 & 4. These parties do not disagree with respect to certain components of the process for removing capitalized expenses (e.g., the use of "Pensions and Benefits" and "Payroll and Withholding" for this purpose). They do apparently differ regarding "Inter-Company Billings." Staff avers that the amounts relating to such billings "have nothing to do with capitalized payroll-related expenses." Staff RBOE at 6. Staff's detailed explanation on this point appears correct. Accordingly, the Commission concludes that Staff's proposed method for removing capitalized payroll-related costs from previous CWC calculations in these dockets should be adopted in all respects. Insofar as Staff's proposal differs from the Utilities', it provides the better approach.

2. Pass-Through Taxes

Staff and the Utilities dispute whether pass-through taxes should be included within the "Taxes Other Than Income Taxes" component of the CWC calculation. The Utilities aver that pass-through taxes have an "indisputable impact" on their cash flow and, therefore, should be taken into account when determining the expense *lead time* of Taxes Other Than Income Taxes. PGL-NS Init. Br. at 27. However, the Utilities claim, it is inappropriate to include the expense *dollars* represented by such taxes in CWC calculations, "because the Companies do not bear ultimate responsibility for pass-through taxes." Id. In other words, the Utilities assert that the timing of pass-through tax expense is pertinent to CWC, but the dollar-amount is not. Thus, $224 million in taxes, including $206 million in pass-through taxes, were used by the Utilities to calculate lead *days*, Staff Ex. 15.0 at 11, but only $17.6 million in taxes[8] (presumably

[8] Since the Utilities do not "bear ultimate responsibility" for *any* taxes, the Commission does not understand why any taxes were included under the Utilities' methodology.

not pass-through taxes) were included to calculate *cash flow* for determining Taxes Other Than Income Taxes.

Staff asserts that pass-through taxes should be excluded in the CWC calculation because they "do not impact the financing of day to day operations. [They] are collected by the [Utilities] from customers and…passed on to the appropriate taxing body." Staff Init. Br. at 9. If pass-through taxes truly impact the Utilities' cash flows, Staff contends, then their dollar amounts would belong in the CWC analysis. "Since they do not, the pass-through taxes were excluded in the [Utilities'] final calculation [of cash flow] and should have been excluded in calculating lead days." Id. at 10. "The effect of including over $206 million of 'pass-through' taxes in the lead days calculation [but not in the dollar calculation] unfairly skews the weight of the lead days toward the shorter lead times and greater amounts of the 'pass-through' taxes." Id. at 9.

Commission Analysis and Conclusion

The parties appear to have reversed the positions they took with regard to inclusion of capitalized payroll items in the CWC analysis. That is, the Utilities, having opposed recognition of the practical impact of payroll-related cash outlays on cash flow, now insist that the practical cash flow impact of tax collection and payment should be recognized in CWC computations. Staff, after emphasizing the real effect of payroll-related items on cash flow, now dismisses the effect of pass-through taxes, even though collected tax revenues enter and leave the Utilities' accounts. The explicit and implicit rationales underlying this role reversal are unpersuasive, although they do (perhaps inadvertently) point the way to an appropriate resolution of this dispute.

To begin, the Commission agrees with the Utilities that tax obligations affect cash flow. The Utilities collect money from ratepayers to meet governmental obligations, then satisfy those obligations with later payments[9]. PGL-NS Ex. 3.0 at 20. But it is irrelevant that the Utilities do not "bear ultimate responsibility" for the taxes they collect. CWC concerns day-to-day financing, not where cash outlays ultimately go. For financing purposes, tax receipts are no different than customer receipts. The Utilities either have the cash flow (including the flow generated by tax recovery) to pay expenses or they need temporary investor financing (CWC). Thus, in the previous subsection of this Order, our exclusion of capitalized payroll items from the CWC analysis was not due to an absence of day-to-day financial impact (indeed, such impact exists), but due to their inclusion in rate base through capitalization. That is not true of taxes. Accordingly, if pass-through taxes are used to determine lead times, the Commission perceives no reason to exclude tax expense dollars from the lead-lag calculation. The dollar-weighting of tax expense leads, for CWC purposes, should reflect all of the Taxes Other Than Income Taxes used by the Utilities to compute lead times[10].

[9] The gas revenue tax is an exception. The Utilities calculate a negative lead for that tax. PGL-NS Ex. MJA-1.0 at 14.

[10] Staff had initially envisioned an alternative result here - that pass-through taxes would be removed from CWC calculations because they "are not recovered through base rates." Staff Ex. 15.0 at 11. In Staff's briefs, however, that proposal seemed to transmute into a recommendation that pass-through taxes remain in CWC, but with real estate taxes accorded separate treatment. Staff Init. Br. at 10. (We address

On exceptions, the Utilities request that we correct a purported error in the Proposed Order whereby the dollar amounts of pass-through taxes were included in the expense lead calculations but not in the Proposed Order's revenue lag calculations. PGL-NS BOE at 9-10. Staff responds that there is no error because pass-through taxes do not create a revenue lag. "There can never be a revenue lag for pass-through taxes because there is no 'date customers receive service' related to receiving pass-through taxes." Staff RBOE at 8. Furthermore, Staff argues, the record contains no evidence of an actual revenue lag associated with pass-through taxes (or any of them). Id. The Utilities instead use the revenue lag for the regulated gas services they provide to customers (49.44 days). Staff avers that the Commission "cannot assume the lag days for revenue would be the same for pass-through taxes without analysis." Id.

Staff's latter argument is incorrect under the Utilities' chosen methodology, which assumes revenue lag for CWC purposes is *always* the monthly interval between delivering gas to the customer and having access to customer payments after they are deposited in the bank. PGL-NS MJA-1.0 at 5. That is, the Utilities bill monthly (and, by measuring from the middle of the service month, calculate that they can access the associated receipts about 49 days later), which, for CWC purposes, they treat as the sole way they obtain customer funds, whether for taxes or other items.

Regarding Staff's first argument – that there is no revenue lag for pass-through taxes – Staff's apparent concern is that pass-through taxes provide no service to the customer and involve no product or service costs (other than tax collection costs, which are presumably recovered as O&M expenses). Moreover, several of the taxes are paid quarterly or annually, which raises the question of how, in common sense, they can have a revenue lag. That said, however, the Utilities still must obtain revenue to remit to the taxing bodies, and the only revenue collection mechanism in the record, with its attendant revenue lag, is the monthly bill. Consequently, while the Commission would welcome additional analysis, as Staff suggests, addressing the movement of pass-through taxes in and out of the Utilities' accounts for CWC purposes, we do not have that analysis here. For now, we will include pass-through taxes in the revenue portion of the gross lag study approved in these dockets.

3. Real Estate Taxes

Real estate taxes have a significantly longer expense lead time than the other taxes included within Taxes Other Than Income Taxes. As figured by the Utilities, the weighted lead time for all Taxes Other Than Income Taxes (including real estate taxes) is 43.67 days, PGL-NS Ex. 1.0 at 13, while the specific lead time for real estate taxes alone is slightly above 380 days. Id. at 16. Consequently, Staff argues that real estate taxes "should be treated separately so the true effect of real estate tax lead is

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that proposal in the next subsection of this Order.) In any case, Staff's multiple citations to our prior Orders, Staff Ex. 15.0 at 12-13, demonstrate its awareness that we have *included* pass-through taxes in prior CWC analyses.

considered." Staff Ex. 15.0 at 12. Staff stresses that property taxes received separate treatment in several prior dockets[11]. Id. at 12-13.

In a manner that the Commission finds not entirely clear, Staff also proposes separate treatment for real estate taxes as a kind of remedy for the Utilities' decision (addressed in the immediately preceding subsection of this Order) to use pass-through taxes in computing expense lead times, but not in computations involving expense lead dollars. "To correct for the [Utilities'] skewing of lead days toward the heavily weighted pass-through taxes…real estate taxes should be treated separately for the effect of lead days for real estate taxes in the CWC requirement calculation." Staff Rep. Br. at 4. Per this proposal, pass-through taxes would remain in the Taxes Other Than Income Taxes lead time calculation, but not in the cash flow analysis, and property taxes would be handled similarly but separately.

The Utilities rejoin that "[s]eparating real estate taxes from other non-income taxes, and thereby failing to dollar weight them, inappropriately affords real estate taxes disproportionate impact on the CWC calculation as compared to all other dollar-weighted, non-income taxes." PGL-NS Init. Br. at 26. Furthermore, the Utilities say, Staff inconsistently recommends distinct treatment for the long lead time associated with property taxes, but not the relatively shorter lead times (when compared to the tax group as a whole) of other non-income taxes. Id.

Commission Analysis and Conclusion

It appears that property taxes appeared on a separate line in the CWC calculations in prior cited cases because the other taxes in Taxes Other Than Income Taxes were treated separately as well. In these proceedings, the Utilities package all of those taxes in a "basket," and maintain that, because of dollar-weighting, the CWC result is no different than if each tax were analyzed separately. PGL-NS Ex. 3.0 at 18. By separating real estate taxes, the Utilities contend, and not dollar-weighting them with the others, Staff reduces CWC[12]. Staff's concern, however, is that the particularly long lead time for property taxes will be "diluted" by inclusion with the other taxes. Staff Rep. Br. at 5.

The Commission will not approve separate treatment for real estate taxes. Although they have the longest lead time among the pertinent taxes, others also have relatively long leads – City of Chicago Use Tax (236 days) and State of Illinois Corporate Franchise Tax (185 days). PGL-NS Ex. 1.0 at 15-16. While we agree with Staff that we do have the discretion to treat atypical tax leads differently, we do not see a meritorious rationale for doing so here. We prefer the consistency of the Utilities' approach, and dollar-weighting mitigates the impact of a longer lead on the cluster of shorter leads among Taxes Other Than Income Taxes. Therefore, when computing

[11] Our research shows that the treatment of property taxes was not in dispute in any of those proceedings.

[12] The Commission cannot be sure of the claimed magnitude of the reductions. Utilities' witness Adams purports to derive the amount of Staff's Taxes Other Than Income Taxes from Staff's filings, but the figures for Staff's Taxes Other Than Income Taxes in MJA-2.1, p. 4, are not identical to the figures in Staff witness Kahle's exhibits. Staff Ex. 15.0, Ex. 15.0, Sch.s 15.1 N & 15.1 P, p. 2 (in each schedule), line 18 (in each schedule).

both the lead times and cash flow impacts of pass-through taxes, as required in the preceding subsection of this Order, *all* such taxes should be utilized as a single "basket" in this instance[13].

In all other (undisputed) respects, the Utilities' calculation of CWC is approved.

F. Gas in Storage

1. Working Capital

a) North Shore/Peoples Gas

To ensure that they will have gas sufficient to fill their customers' needs, the Utilities purchase gas and inject it into storage fields. For accounting purposes, the Utilities initially record all such stored gas as working inventory. Later, based on studies performed to determine the percentage of stored gas that should be considered "working" or "top" gas and the percentage that should be considered "cushion" or "base" gas, the Utilities reclassify appropriate quantities of top gas and record it as base gas. PGL-NS Ex.-TEZ 3.0 at 37.

In accordance with the Uniform System of Accounts, the Utilities explain that stored gas classified as top gas is included in rate base as working capital and recorded as Gas in Storage. They further explain that gas which is classified as base gas is included in rate base as part of net plant. *See, e.g.,* PGL Ex. SF-1.0 at 11, NS Ex. SF-1.0 at 11; 83 Ill. Admin. Code 505.1170, 505.1641.

Based on 13 month averages as of the end of the test year, fiscal year 2006, *i.e.,* as of September 30, 2006, Peoples Gas' working capital allowance in rate base for Gas in Storage is $86,667,000, and North Shore's is $10,507,000. *E.g.*, PGL Ex. SF-1.0 at 15-16; PGL Ex. SF-1.1, Sched. B-1, line 6 and Sched. B-8.1, column [M]; NS Ex. SF-1.0 at 15; NS Ex. SF-1.1, Sched. B-1, line 6 and Sched. B-8.1, column [M].

b) Staff

Staff recommends a reduction of $13,549,797 to Peoples Gas' requested $86,667,000 working capital allowance associated with gas in storage due to Peoples Gas maintaining 6,896,183 Mcf of storage gas in excess of normal levels. Staff Ex. 23.0 at 6-7. Staff also recommends a reduction of $1,422,772 to North Shore's requested $10,507,000 working capital allowance associated with gas in storage due to North Shore maintaining 866,543 Mcf of storage gas in excess of normal levels. Id*.* at 15-16.

Staff maintains that the gas storage volumes, that the Utilities would include in the test year, greatly exceeds their respective historical storage volumes. Id*.* at 6 and 15. According to Staff, Peoples Gas' requested test year gas volume (Fiscal Year 2006: October 1, 2005 to September 30, 2006) was on average more than 4 Bcf[14] higher than

[13] To provide clarity for future proceedings, we note that we are neither *requiring* "basket" treatment of Taxes Other Than Income Taxes nor prohibiting line item treatment of those taxes. Rather, we are merely approving the Utilities' "basket" treatment as an acceptable option, with the *requirement* that all such taxes belong in the basket.

[14] Bcf is equal to 1,000,000 Mcf or 1,000,000,000 cubic feet.

the prior two fiscal years (Fiscal 2005 and 2004) and more than 10 Bcf higher than Fiscal Years 2003 and 2002. Staff Ex. 11.0 at 7-8 and Staff Ex. 11.0, Schedule 11.3P. North Shore's requested test year gas storage volume was about 900,000 Mcf higher than the storage volume from the prior 4 fiscal years. Id. at 25.

Staff argues that the revenue requirement determined in the instant proceeding should be based upon normal conditions. Id. Staff notes that the information provided by the Utilities in response to Staff data request ENG 7.05 allowed for a comparison of the number of heating degree days assumed for the test year against the actual number of degree days for fiscal years 2002 through 2006. This data, Staff explains, showed that none of the historical fiscal years provided a match for the heating degree days the Utilities assumed as part of the normalized test year. Id. at. 9 and 17-18. As such, Staff concluded that the Utilities' requested amounts were not based on normal conditions and this contributed to their maintaining a larger than normal volume of storage gas. Id. at 8 and 17.

Staff states that it further requested the Utilities to provide the storage volumes they had assumed would occur if a normal year occurred in the test year. Id. at 9 and 18. Staff explains that it used this information (provided in response to Staff data request ENG 7.10), to calculate the volume of gas the Utilities would have maintained in the test year under normal conditions; Staff then used that normalized volume to determine the appropriate working capital allowance for gas in storage. Id. and Staff Ex. 23.0, Schedules 23.2P and 23.2N.

According to Staff, this calculation showed that Peoples Gas needed to reduce its gas in storage volume by 6,896,183 Mcf, and this is the basis for Staff's recommended adjustment of $13,549,797. Staff Ex. 23.0 at 9 and Staff Ex. 23.0, Schedule 23.1P. Staff states that it performed the same calculations for North Shore Gas' storage volumes, and concluded that North Shore needed to reduce its gas in storage volume by 866,543 Mcf and this is the basis for Staff's recommended adjustment of $1,422,772. Staff Ex. 23.0 at 18 and Staff Ex. 23.0, Schedule 23.1N.

Staff's review is included in the rebuttal testimony of Eric Lounsberry, and it reflects that the Utilities' requested working capital allowance for their gas in storage amounts involved storage volumes that were significantly higher than historical levels and that the test year volumes were overstated due to the warmer than normal weather during the test year. The Utilities did not dispute Staff's conclusions in their surrebuttal testimonies. Therefore, Staff's recommended reduction to working capital allowance for gas in storage for both Utilities, which was based upon the Utilities' expected test year storage activity under normal weather conditions, should be accepted.

Staff observes the Utilities to have explained that their excess gas in storage is a result of warmer than normal weather conditions. NS-PGL Ex. TZ-2.0 at 74. As such, the Utilities pointed out that the winter of 2006[15] was the fifth warmest on record, and that January 2006 was the warmest January on record. Id. On these bases, Staff

[15] The Utilities' test year of October 1, 2005, through September 30, 2006, (Fiscal 2006) included the winter of 2006.

observes the Utilities to conclude that these warmer than normal temperatures contributed to the increased test year storage volumes maintained by both Utilities. Id.

Staff points out that, as even Peoples Gas admits, its excess test year inventory is due to warmer than normal weather conditions in the test year. On record, Staff asserts, it demonstrated that these test year volumes are significantly higher than the historic gas storage volumes for both of the Utilities. As such, Staff contends it properly normalized the gas storage volumes requested by the Utilities to determine a normalized working capital allowance for gas in storage.

Staff notes too that the Utilities' arguments only address inventory volumes at Manlove field and do not consider leased storage. According to Staff, however, the analysis performed by its witness considered three leased storage services in addition to Manlove field for Peoples Gas (Staff Ex. 23.0, Schedule 23.2P) and considered two leased storage services in addition to Manlove field for North Shore. Staff Ex. 23.0, Schedule 23.2P. Thus, Staff asserts, there is more involved here than just Manlove storage.

In setting rates, Staff observes that the Commission has historically viewed larger than normal values for gas in storage as not meeting the legal just and reasonable standard. For example, Staff notes that in the Order for Dockets 02-0798, 03-0008, 03-0009 (October 22, 2003), the Commission accepted Staff's arguments that the storage inventory levels were excessive and reduced the working capital allowances associated with gas in storage. Id. at 22. Here too, Staff argues, the Commission should accept Staff's recommended reductions to working capital allowance for gas storage

c) North Shore/Peoples Gas Response

The Utilities oppose Staff's recommendation that the Commission reduce their Gas in Storage simply because there was more gas in storage at the end of the test year than at the end of certain prior years. The Utilities explain that the difference in circumstance was primarily due to weather. According to the Utilities, the exceptionally warm winter in 2006 caused them to pull less gas out of storage to meet customer needs than they might otherwise have had to withdraw. NS-PGL Ex. TEZ-2.0, 74:1636-46. The Utilities also point out that Staff itself concedes that a utility does not necessarily cycle all of its working gas, depending on the winter weather. D. Anderson, Tr. at 473:11-18.

The Utilities further explain that Staff's proposed adjustment to working inventory should have no net impact on total rate base. In accordance with applicable regulatory requirements, the Utilities assert, they are allowed to include the cost of all gas stored underground in their rate base, e.g., PGL Ex. SF-1.1, Sched. B-1, lines 1, 6; 83 Ill. Admin. Code §§ 505.1170, 505.1641. And, they argue, this is so regardless of whether that gas is classified as top gas or base gas. Thus, the Commission's acceptance of Staff's proposed disallowance relative to the Utilities' working capital allowance for Gas in Storage would mean, at most, that the value of the Utilities' base gas would have to be adjusted upward by an equal amount.

d) Commission Analysis and Conclusion

As an initial matter, the Commission notes that neither the arguments of the Utilities nor those of Staff, are models of clarity in dealing with the issue at hand. The Utilities appear to suggest that they are entitled to include in rate base the level of natural gas actually in storage during the test year, period. They fixate on the fact that the natural gas actually exists and that gas in storage is either top gas or base gas. And, the Utilities assert that they are allowed to include both top gas and base gas in rate base and, therefore, all gas in storage should be included in rate base.

In the Commission's view, it is true that natural gas can serve the function of either top gas or base gas and that by definition the gas in storage is either one or the other. The Utilities' idea that natural gas can simply be converted from top gas to base and back again, is not a view that the Commission shares. As the Commission understands it, base gas is the quantity of gas in storage needed for a storage field to operate properly; that is, allow the top gas to be injected and withdrawn to meet the needs of utility customers. While the quantity of gas that is classified as base gas is subject to revision in some circumstances, it does not fluctuate as the Companies seem to suggest.

It appears that Staff has done the better job in focusing on the proper question before the Commission, i.e., whether the Utilities had more top gas in storage than was necessary to meet the needs of utility customers during the test year. The evidence of record appears to support the theory that due to warmer than normal weather during the test year, the Utilities did not withdraw as much top gas from storage as they would during a normal or colder than normal year. This does not indicate that the Utilities did anything wrong. It does explain; however, why they had more top gas in storage during the test year than is necessary to meet the needs of their customers. Contrary to what the Utilities suggest, they are not necessarily entitled to include in rate base all gas in storage.

In proposing its adjustment, Staff looked to the difference between the quantities of underground gas on hand at the end of the test year as opposed to other years. The Utilities contend that the test year was unusual. But, this is precisely why a historical review is necessary and we expect that Staff took the weather differences from this data into account when assessing whether the volume that is set out as working inventory in the test year is fairly representative of the volumes going forward. According to Staff, it is not.

In conclusion, the Commission finds that Staff has demonstrated that the Utilities had more top gas in storage than necessary to meet their customer needs. Thus we approve Staff's proposed downward adjustments to the working capital requirements of Peoples Gas and North Shore for gas in storage. Nothing in the Utility's BOE persuades us otherwise.

2. Accounts Payable

a) Peoples Gas/North Shore

The Utilities maintain that they correctly did not include any offset for accounts payable in their Gas in Storage figures. They dispute Staff's claim that there should be deductions of $26,727,000 from Peoples Gas' Gas in Storage in rate base and $6,098,000 from North Shore's Gas in Storage in rate base, based on the theory that vendors financed these purchases and, therefore the storage gas included in each rate base should be reduced by the related amounts of accounts payable "because the Companies should not earn a return on the storage gas until it has been funded by investors." Kahle Corr. Supplemental Dir., Staff Ex. 3.0 Supp., 2:37-42.

According to the Utilities, their witness Fiorella provided uncontradicted testimony showing that the Utilities paid for the Gas in Storage in rate base, and that there are no accounts payable for the Gas in Storage in rate base because, under the applicable standard contract, the Utilities paid for this storage gas within no more 16 days from the receipt of the invoices from the vendors. NS-PGL Ex. 3.0 at 2. He stated quite simply that: "The item in question, gas storage inventory balances, is based on historical costs, which have been paid for and financed by the Utilities." Id. at 4:71-73. It is already established, the Utilities note, that their Gas in Storage in rate base is based on 13 month averages as of the end of the test year, fiscal year 2006, i.e., as of September 30, 2006. *E.g.* ,PGL Ex. SF-1.0 at 15-16; PGL Ex. SF-1.1, Sched. B-1, line 6, and Sched. B-8.1, column [M]; NS Ex. SF-1.0 at 15; NS Ex. SF-1.1, Sched. B-1, line 6, and Sched. B-8.1, column [M]. Hence, the Utilities argue, the accounts payable relating to the Gas in Storage in rate base were paid, at least, over a year ago, and in each instance they were paid no more 16 days from when the Utilities received the invoices from the vendors. According to Staff's own witness, "the Companies should not earn a return on the storage gas until it has been funded by investors." Staff Ex. 3.0 Supp., 2. This is just the situation here, the Utilities assert, in that the Gas in Storage in rate base is fully funded by investors -- it has been for over a year.

The Utilities note that Staff's rebuttal testimony does not deny that the accounts payable related to the Gas in Storage in rate base have been paid. Instead, Staff's witness offers the revised theory that his proposed adjustments should be approved because Gas in Storage purchased after the test year will be "financed" by vendors. Staff Ex. 15.0 at 18-19. Even at that, the Utilities argue, Staff's witness does not, and cannot deny, that such "financing" consists of nothing more than the fact that the Utilities pay vendors' invoices for storage gas in no more than 16 days. He does not and cannot deny that the Utilities must, and do, pay those invoices. The thrust of Staff's position, the Utilities observe, is to unreasonably deny the Utilities recovery of and on substantial amounts of their actual historical investments in the Gas in Storage in rate base simply because they do not instantly pay for gas in storage.

Staff's witness refers to five Commission Orders that he contends support his position, including the Utilities' 1995 rate cases but, as he acknowledged, all five involved future test years. Staff Ex. 15.0 at 20. Staff's position, and the application of those five Orders to the instant proceedings, which involve an historical test year, not a future test year, does not fit the facts, is inappropriate, and also unfairly fails to take into account regulatory lag, i.e., the delay between the large cost under-recovery experienced by the Utilities during the test year through the period when the rates will go into effect beginning in 2008. NS-PGL Ex. SF-3.0 at 3-4; NS-PGL Ex. 4.0 at 7 8. Staff's proposed adjustments to impose accounts payable offsets against the Gas in Storage in rate base lack merit and should not be approved.

b) Staff

Staff witness Kahle proposed adjustments to the Gas in Storage the Utilities had included in rate base. According to Mr. Kahle, his adjustments removed costs which were not financed by investors and were not supported by actual expenditures. These costs were supported by accounts payable, and as such, were funded by vendors. Staff contends that the Utilities should not earn a return on that Gas in Storage. Staff Ex. 15.0 Corrected, at 17-18; Id. Schedules 15.3 N and P at 1.

Staff observes Utilities witness Fiorella to have agreed that, to the extent that the Utilities have not paid for a good or service that has been received, an accounts payable exists on the Utilities' books, and the vendor has provided temporary financing. While Mr. Fiorella went on to state that no adjustment should be made because the account payable no longer existed; he did not contend that the accounts payable did not exist during the test year. North Shore/Peoples Gas Ex. SF-3.0 at 2-3. In fact, the amount of the Gas in Storage adjustment was calculated using accounts payable balances supplied by the Utilities in a data request response. Staff Ex. 15.0, Schedules 15.3 N and P, at 2.

Staff notes Mr. Fiorella to have stated that the accounts payable no longer existed at the end of the test year. In response, however, Mr. Kahle made the point that as certain accounts payable are paid; other accounts payable are created in the normal gas purchasing cycle such that a portion of Gas in Storage would continue to be financed by vendors through accounts payable, Staff Ex. 15.0, at 19, and the Utilities at no time offered that any other items that might have expired since the end of the test year should be excluded; such as, the Gas in Storage that was reported on the Utilities' Schedule B-1 which may have been withdrawn and consumed by ratepayers since the end of the test year. Staff Ex. 15.0 Corrected at 19.

Mr. Fiorella made the additional argument that no adjustment related to accounts payable should be made to Gas in Storage because the Utilities had filed a historic test year. PGL-NS Ex. SF-3.0 at 3; Staff claims, however, that the accounts payable for gas in storage should received the same treatment as accounts payable for materials and supplies. Staff Ex. 15.0 Corrected at 18-19.

As further support for its adjustment, Staff notes that in the Utilities' previous rate cases, i.e., Dockets 95-0031 and 95-0032; Orders at 5-6 (November 8, 1995), the Commission accepted an adjustment to reduce Gas in Storage by associated accounts payable. Further, Staff observes that the Commission applied the same treatment in its Orders for Docket 04-0779 (Nicor Gas Company); Docket 93-0183, (Illinois Power Company); and Docket 95-0219 (Northern Illinois Gas Company). Staff Ex. 15.0 at 20, Corrected.

The Utilities' argument over an historical test year verses a future test year does nothing, in Staff's view, to show that accounts payable will not continue to exist. Further, Staff considers the Utilities' reference to regulatory lag to be misplaced. In the end, Staff recommends that the Commission adopt its adjustment for accounts payable associated with storage gas as presented on Schedules 15.3 N & P by reducing Gas in Storage included in rate base for the related accounts payable by $6,098,000 for North Shore and by $26,727,000 for Peoples Gas.

c) North Shore / Peoples Gas Response

The Utilities assert that Staff's proposed adjustments to impose accounts payable offsets against the Gas in Storage in rate base are unjustified and should be rejected. The Gas in Storage in rate base, they argue, is fully funded by investors and has been for over a year. The Utilities paid for the Gas in Storage in rate base, and there are no accounts payable for the Gas in Storage in rate base. Under the applicable standard contract, the Utilities paid for this storage gas within 16 days from the receipt of the invoices from the vendors. NS-PGL Ex. 3.0 at 2. Further, the Utilities' Gas in Storage in rate base is based on thirteen month averages as of the end of the test year, fiscal year 2006, i.e., as of September 30, 2006. *E.g.,* PGL Ex. SF-1.0 at 15-16; PGL Ex. SF-1.1, Sched. B-1, line 6, and Sched. B-8.1, column [M]; NS Ex. SF-1.0 at 15; NS Ex. SF-1.1, Sched. B-1, line 6, and Sched. B-8.1, column [M]. Hence, the accounts payable relating to the Gas in Storage in rate base were paid over a year ago, and in each instance they were paid no more than 16 days from when the Utilities received the invoices from the vendors.

According to the Utilities, Staff does not dispute that the Utilities paid in full for the Gas in Storage included in their rate bases over a year ago and, they assert, the evidence of that fact is uncontradicted. Further, the Utilities note that Staff's own witness agreed that storage gas should be included in rate base if it has been funded by the Utilities. *See* Staff Ex. 3.0 Supp at 2.

Instead, the Utilities note Staff's rebuttal testimony and its Initial Brief makes much of the fact that the amounts of Gas in Storage in the Utilities' rate bases include amounts as of the end of the test year, i.e., <u>as of September 30, 2006</u>. On this basis, the Utilities observe Staff to conclude this to mean that a portion of the Gas in Storage balances was "financed by vendors" <u>as of September 30, 2006</u>. Staff Init. Br. at 14-15. The Utilities consider Staff's brief to be a bit imprecise. According to the Utilities, the amounts in rate base were calculated using the averages of balances in the thirteen months ending on September 30, 2006. PGL Ex. SF-1.1, Sched. B-1, line 6, Sched. B-8.1, column [M]; NS Ex. SF-1.1, Sched. B-1, line 6, Sched. B-8.1, column [M].

The Utilities argue that Staff's point, i.e., that there were accounts payable for Gas in Storage as of September 30, 2006, does not mean that the Utilities did not pay for the Gas in Storage in rate base. Although the thirteen-month average included the balance for the month ending <u>on September 30, 2006</u>, and there were accounts payable as of that date, the Utilities paid off the last amounts owed for a fraction of the Gas in Storage in rate base <u>no later than October 16, 2006</u>. The Utilities maintain that this is no reason to disallow any of the costs of the Gas in Storage in rate base.

Staff also overlooks the net balances for storage gas as of September 30, 2006. Peoples Gas' storage gas balance as of September 30, 2006, was $127,746,000 (PGL Ex. SF-1.1, Sched. B-8.1, line 13, column [M]), while the accounts payable as of that date were $26,652,159 (Staff Ex. 15.0, Sched. 15.3 P, p. 2, line 13), yielding a net balance of $101,093,841. Peoples Gas only included $86,667,000 of Gas in Storage in its rate base. Thus, the net balance as of September 30, 2006, is <u>lower</u> than the amount in Peoples Gas' rate base. The same is true as to North Shore. *See* NS Ex. SF-1.1, Sched. B-8.1, line 13, column [M]; Staff Ex. 15.0, Sched. 15.3 N, p. 2, line 13. Thus, for this additional reason, the accounts payable balances as of September 30, 2006, do not warrant any disallowance.

The Utilities note Staff's Initial Brief to fall back on its witness' theory that, after the test year, the Utilities continued and will continue to use and buy storage gas, and this means that vendors will continue to "finance" storage gas, i.e., they will send invoices that are paid by the Utilities within a maximum of 16 days. *See* Staff Init. Br. at 15. According to the Utilities, this also is no reason to disallow any of the costs of the Gas in Storage in rate base, for which the Utilities paid in full.

Staff makes the point that some of the Gas in Storage included in rate base may have been withdrawn and consumed by customers since the end of the test year. Staff Init. Br. at 15. However, as noted above, the Gas in Storage amounts in the rate bases are based on thirteen-month averages, so they already reflect the test year's injections and withdrawals.

Staff also argues that their proposed adjustments are supported by the treatment of materials and supplies balances. Staff Init. Br. at 15. The Utilities, in their filings, in order to narrow the likely contested issues, chose not to contest materials and supplies accounts payable offsets, but that is not a reason to adopt the same as to Gas in Storage. Also, as Staff's exhibits show, for much of the year, the Utilities owe zero accounts payable for Gas in Storage. Staff Ex. 15.0, Sched. 15.3 P at 2., lines 4-7, Sched. 15.3 N at 2, lines 3-7. The facts that, some of the time, the Utilities owe amounts for Gas in Storage, and that they pay the invoices for that storage gas within no more than 16 days, do not justify disallowances.

Finally, the Utilities observe Staff to cite other rate cases where the Commission approved accounts payable offsets to Gas in Storage balances. Staff Init. Br. at 15-16. According to the Utilities, however, these cases do not support Staff's proposed adjustment. Unlike the situation in these proceedings, the cases on which Staff relies each involve future test years where the utilities have not yet paid for the Gas in Storage in their rate bases, and because the use of a future test year mitigates the regulatory lag of an historical test year rate case. NS-PGL Ex. SF-3.0 at 3-4; NS-PGL Ex. SF-4.0 at 7-8. The Utilities' Gas in Storage in their rate bases should be approved in full, not offset by accounts payable to deny them recovery on amounts they in fact have paid.

d) Commission Analysis and Conclusion

The Commission considers Staff's proposed adjustments to impose accounts payable offsets against the Gas in Storage in rate base and the Utilities' challenges to that proposal.

The Utilities maintain that while vendors arguably “finance” the storage gas, they pay vendors’ invoices in no more than 16 days. This is the main thrust of their argument. In Staff’s view, however, there is value to the Utilities during the term of those 16 days. Indeed, Staff considers the assertion that accounts payable are paid within sixteen days to confirm rather than disprove, that the accounts payable exist. Regardless of when the accounts payable were paid, Staff goes on to tell us, the fact remains that costs for gas in storage are continually being incurred and that there is a continual level of gas in storage that is supported by accounts payable. And, Staff asserts, the Utilities should not earn a return on that gas in storage.

We note too that what Staff asks be done in this instance is nothing new. In other words, there are a number of other cases where we made similar adjustments. The Utilities’ attempts to distinguish these earlier situations from the present case are not convincing.

Staff bases the amount of its adjustment on accounts payable figures provided by the Utilities in a data request response. Staff Ex. 15.0 Corrected, Schedules 15.3 N and P at 2. While a more detailed discussion of Staff’s methodology would have been useful, we do not see the Utilities to present any challenges on Staff’s calculation.

Accordingly, the Commission adopts Staff’s adjustment for accounts payable associated with storage gas as presented on Schedules 15.3 N & P by reducing Gas in Storage included in rate base for the related accounts payable by $6,098,000 for North Shore and by $26,727,000 for Peoples Gas. Nothing in the Utilities’ BOE persuades us differently in these premises.

G. OPEB Liabilities and Pension Asset/Liability

1. North Shore / Peoples Gas

Peoples Gas, in calculating its rate base, included neither its net pension asset of $110,000,000 nor its net OPEB liability of $31,570,000 (gross amount $55,563,000). *See, e.g.*, NS-PGL Ex. LMK-2.0 2REV at 12-13; Staff Init. Br., App. A Corr., at 6, column (k).

North Shore, in calculating its rate base, included neither its net pension liability of $24,000 nor its net OPEB liability of $4,074,000 (gross amount $7,094,000). *See, e.g.*, NS-PGL Ex. LMK-2.0 2REV at 12-13; Staff Init. Br., App. B Corr., at 5, column (h). Thus, if the Utilities had included their respective pension asset/liability and OPEB liabilities, which symmetrical treatment would require, NS-PGL Ex. LMK-2.0 2REV at 13; NS-PGL Ex. LMK-3.0 at 3, then Peoples Gas’ rate base would have increased by a net $78,430,000, and North Shore’s rate base would have decreased by a net $4,098,000. During the test year, fiscal year 2006, Peoples Gas and North Shore point out that they contributed $15,278,614 and $1,862,247, respectively, to the pension plan. NS-PGL Ex. LMK-3.0 at 3.

2. The GCI Parties

(The AG and the City-CUB hold to the same position on this issue).

The GCI explain that Peoples Gas and North Shore accrue liabilities for Other Post Employment Benefits ("OPEB") pursuant to Statement of Financial Accounting Standards 106 ("FAS 106"). According to GCI witness David Effron, the Utilities have accrued OPEB liabilities to the extent that the cumulative accruals are greater than the actual cash disbursements for the post retirement benefits. GCI Ex. 2.0 at 11-12. As such, the accrued liabilities represent the expenses accrued in excess of actual payments for OPEB. Id*.* As of September 30, 2006, i.e., the end of the test year, the accrued liability for OPEB was $7,094,000 for North Shore and $55,653,000 for Peoples. Id*.*

CGI witness Effron testified that each Company's test year rate base should reflect the OPEB deduction. GCI Ex. 2.0 at 13. Likewise, the AG points out, Staff witness Bonita Pearce concurred with Mr. Effron's adjustment, and she noted that ratepayers have supplied funds for future obligations, such that a source of cost-free capital has been provided to the utility which should be recognized in the revenue requirement as a reduction from rate base. Staff Ex. 14.0 at 21-22.

City-CUB maintain that the Utilities' failure to deduct their accrued OPEB liability from rate base violates established Commission policy. In the Order for Docket 95-0219 (Northern Illinois Gas Company),they note, the Commission held that as long as the utility continues to control the ratepayer-supplied OPEB funds, the OPEB deduction should be recognized in the determination of rate base. Docket 95-0219, Order at 10. In that same utility's subsequent rate case, the Commission again applied this policy in determining rate base, and deducted $97,393,000 of "Retirement Benefits, Net" (comprised of the accrued OPEB liability) from the utility's plant in service. Id*.* at 31. And, in Docket Nos. 06-0070, et al. (cons.) (AmerenCILCO, AmerenCIPS, AmerenIP), the Commission confirmed this precedent, by finding that the accrued OPEB liability should be removed from rate base.

In this case, the GCI point out, the Utilities have failed to present any reason for the Commission to deviate from its established policy. Accordingly, they argue, the Commission should reflect a rate base deduction of $7,094,000 ($4,074,000 net of related deferred taxes) for the North Shore accrued OPEB liability and a rate base deduction of $55,653,000 ($31,570,000 net of related deferred taxes) for the Peoples Gas accrued OPEB liability in the determination of the Utilities' rate bases. *See* GCI Ex. 2.0 at 13.

3. Staff

Other Post Employment Benefits ("OPEB") liability, Staff explains, is the employer's obligation for post retirement benefits generally, such as health care, life insurance, tuition assistance and other types of post retirement benefits outside of a pension plan. In the instant proceeding, Staff asserts, the accrued OPEB liability represents a cost-free source of capital and should be treated for ratemaking purposes as a reduction of rate base. Staff Exhibit 14.0, at 21.

Staff witness Bonita Pearce agrees with GCI witness Effron's adjustment to reduce utility rate base for the accrued OPEB liability. Staff Exhibit 14.0 at 20 – 24. Additionally, Ms. Pearce disagrees with Utilities' witness Kallas regarding her assertion that if utility rate base were reduced by accrued OPEB liability, the pension asset/liability should also be reflected in rate base.

For ratemaking purposes, Staff explains, a rate base reduction of the accrued liability associated with OPEB is appropriate to the extent that the test year obligation is unfunded or partially funded. The accrued liability represents the aggregate OPEB costs recognized in the income statement which has not been paid to a third party. Ratepayers have supplied funds for future obligations; therefore, a source of cost free capital has been provided to the utility which should be recognized in the revenue requirement as a reduction from rate base. Id. at 21-22.

Staff views Ms. Kallas' assertion as inconsistent with ratemaking theory because the pension asset of Peoples and the pension liability of North Shore do not represent elements of rate base that should impact the return to shareholders. The respective asset/liability was not created with funds supplied by shareholders, and for this reason, shareholders do not need to earn a return on such amounts. Staff Exhibit 14.0, at. 22.

Staff notes that the treatment of OPEB liability was considered in the most recent Northern Illinois Gas Company rate proceeding, Docket 04-0779 and in the Ameren Utilities' latest request for an increase in delivery service tariffs ("DST"), Dockets 06-0070, 06-0071, and 06-0072, consolidated (AmerenCILCO, AmerenCIPS, AmerenIP) Order at 27, (November 21, 2006), as fully cited by Mr. Effron in direct testimony. GCI Exhibit 1.0, at 13. In these cases, Staff informs, the Commission found that the OPEB liability should be treated as a reduction of utility rate base. Staff Exhibit 14.0 at 23.

Further, Staff notes that the Commission addressed the issue of pension asset treatment in Docket 04-0779, and in Docket 95-0219. In both instances, the Commission found that the pension asset was created by ratepayer-supplied funds, not by shareholder-supplied funds. As such, it concluded that ratepayers should not be denied the benefits associated with the previous overpayment for pension expense which they funded and that the pension asset should be eliminated from rate base. Staff Exhibit 14.0 at 23.

4. North Shore / Peoples Gas Response

The Utilities observe that GCI and Staff would have the Commission subtract the Utilities' OPEB liabilities from their rate bases, and further have it ignore Peoples Gas' pension asset and North Shore's pension liability and their pension contributions. The AG's Initial Brief (at 11-13), and the City-CUB Initial Brief (at 16-18), take that position without even mentioning the Utilities' pension asset/liability and pension plan contributions, much less providing any grounds for disregarding them while including the OPEB liabilities. GCI and Staff's proposed reductions of $55,563,000 and $7,094,000 from the rate bases of Peoples Gas and North Shore, respectively, are unfair and one-sided and should be rejected, the Utilities here argue.

The Utilities observe Staff to claim that subtracting the OPEB liabilities from rate base but ignoring the pension asset/liability is consistent with "ratemaking theory" because "the respective asset/liability was not created with funds provided by shareholders. Because these amounts were not provided by shareholders, shareholders do not need to earn a return on such amounts. (Staff Exhibit 14.0 at 22)."

Staff Init. Br. at 18. According to the Utilities, Staff's claim completely ignores the uncontested facts that Peoples Gas' net pension asset reflects that it contributed $15,278,614 to the pension plan during the test year, while North Shore's very small pension liability reflects that it contributed $1,862,257 to the pension plan during the test year. NS-PGL Ex. LMK-3.0 at 3. The Utilities maintain that ratepayers have benefited from those contributions. In calculating their proposed revenue requirements, the levels of pension expense in the test year were reduced by the Utilities' *pro forma* adjustments to reflect the lower levels of pension expense in fiscal year 2007, in the gross amounts of $1,277,000 as to Peoples Gas and $490,000 as to North Shore. PGL Ex. SF-1.0 at 27; PGL Ex. SF-1.1, Sched. C-1, column [D], Sched. C-2, at 1, line 15, and Sched. C-2.15, NS Ex. SF-1.0 at 25; NS Ex. SF-1.1, Sched. C-1, column [D], Sched. C-2, at 2, line 15, and Sched. C-2.15.

The Utilities note Staff to cite the 2004 and 1995 Nicor Gas rate cases where the Commission approved rate bases that reflected deductions for OPEB liabilities but did not incorporate pension assets. But, as the Utilities see Staff to acknowledge, in both of these cases the Commission found, as a matter of fact, that the pension assets were created by ratepayer-supplied funds. Staff Init. Br. at 18.

The Utilities observe that the Commission expressly noted, in the 2004 case, that Nicor Gas acknowledged making no pension plan contributions since the 1995 case. In re Northern Illinois Gas Co., ICC Docket No. 04-0779, Order at 2, Sept. 20, 2005 ("Nicor 2005"). Similarly, they note, the Order in the 1995 case indicates that the pension balance had gone from negative to positive since the utility's 1987 rate case without any pension plan contributions. In re Northern Illinois Gas Co., ICC Docket No. 95-0219, 1996 Ill. PUC Lexis 204, *20, Order, April 3, 1996 ("Nicor *1996*"). And, the Commission's order in Nicor 1996 distinguished the Commission's approval of inclusion of a pension asset in rate base In re Central Illinois Light Co., Docket No. 94-0040, Order, Dec. 12, 1994, on the grounds that the utility there, unlike Nicor Gas, had made pension plan contributions and the inclusion was not a contested issue. Nicor 1996 at *22. Thus, the Utilities assert, the Nicor 2005 and Nicor 1996 Orders do not support Staff's and GCI's proposed adjustments, because the relevant facts as relied upon by the Commission are not the same, and the more telling 1994 CILCO case supports inclusion.

According to the Utilities, Staff's witness also referenced the Commission's exclusion of a pension asset in In re Commonwealth Edison Co., ICC Docket No. 05-0597, Order at 38-40, July 26, 2006, ("ComEd 2006"). Staff Ex. 14.0 at 24. In ComEd 2006, the Utilities observe, the Order on Rehearing did not include the pension asset in rate base, but it allowed the utility to recover a rate of return (based on the cost of long-term debt) on a pension plan contribution that it made shortly after the test year, that was funded by an equity contribution from the utility's ultimate parent company, and that was a major factor in a *pro forma* adjustment to reflect a lower level of pension expense in the year after the test year. Order on Rehearing at 28-29, Docket 05-0597 (December 20, 2006).

As such, the Utilities assert that GCI's and Staff's position, i.e., that OPEB liabilities should be deducted when calculating the Utilities' rate bases, should be rejected. The proposed reductions are incomplete and one-sided in that they exclude Peoples Gas' net pension asset of $110 million, to which Peoples Gas contributed over $15 million in the test year, along with North Shore's net pension liability of $24,000. In the alternative, if the OPEB liabilities are to be deducted, then Peoples Gas' net pension asset of $110,000,000 and North Shore's net pension liability of $24,000 also should be incorporated in the calculation of their rate bases. Further in the alternative, the Utilities maintain, if the OPEB liabilities are to be deducted, then at a minimum, Peoples Gas' contributions of $15,278,614 and North Shore's contributions of $1,862,247 to the pension plan also should be incorporated in the calculation of their rate bases.

5. Commission Analysis and Conclusion

The Commission agrees with the positions asserted by GCI and Staff. Their arguments are persuasive and fully supported by the evidence. Further, they have each established that the treatment we are being urged to assign to this item today, is the same the treatment that we adopted in a number of previous decisions. On all these grounds, the Commission accepts that a rate base deduction of $7,094,000 ($4,074,000 net of related deferred taxes) is required for the North Shore accrued OPEB liability and a rate base deduction of $55,653,000 ($31,570,000 net of related deferred taxes) is required for the Peoples Gas accrued OPEB liability in the determination of the Utilities' rate bases. *See* GCI Ex. 2.0 at 13.

Further, we note that the underlying rationale for these adjustments is that such funds are supplied by ratepayers and not by shareholders such that shareholders are not entitled to earn a return on these funds. Accordingly, the undisputed record showing that Peoples Gas and North Shore contributed $15,278,614 and $1,862,247, respectively, to the pension plans during the test year, does not change the treatment of the OPEB liability. Nor are we convinced that such contributions should impact shareholders, given that these funds were provided by ratepayers through the collection of utility revenues. We observe no discussion of or opposition to this particular recalculation that the Utilities propose on basis of their contribution, however, it appears to the Commission that recognizing these contributions is inconsistent with, the theoretical basis that we are applying here, i.e, these contributions are ratepayer-funded.

The Commission finds that the Utilities' OPEB liabilities will be deducted, and, for the reasons provided by Staff, Peoples Gas' contributions of $15,278,614 and North Shore's contributions of $1,862,247 to the pension plan should not be incorporated into the calculation of the rate bases.

H. ADIT (Derivative Adjustments from Uncontested and Contested Issues)

Other than GCI's two uncontested proposed adjustments discussed in Section II(B)(5) and (6) of this Order, Staff and Intervenors have not proposed any independent adjustments to ADIT as such. Accordingly, and as to ADIT, our Order need only make derivative calculations reflecting the approved adjustments that have derivative impacts on ADIT.

I. Overall Conclusion on Rate Bases

Based on the gas utility rate base as originally proposed by Peoples Gas along with the conclusions *supra*, the gas utility rate base for Peoples Gas approved for purposes of this proceeding is $1,212,203,000. The rate base may be summarized as follows:

Peoples Gas Rate Base (in thousands)

Description	Rate Base
Gross Utility Plant	$ 2,429,226
Accumulated Provision for Depreciation and Amortization	(934,152)
	-
Net Plant	$ 1,495,074
Additions to Rate Base:	
Materials and Supplies	8,796
Cash Working Capital	25,514
Gas in Storage	46,390
Budget Plan Balances	14,080
Unamortized Rate Case Expense	-
Pension Contribution	-
Deductions From Rate Base:	
Accumulated Deferred Income Taxes	(284,954)
Pre-1971 Investment Tax Credits	(54)
Reserve for Injuries and Damages	(4,422)
Customer Advances for Construction	(392)
Customer Deposits	(32,176)
Accrued Postretirement Benefits Other than Pensions ("OPEB")	(55,653)
Rate Base	$

1,212,203

Based on the gas utility rate base as originally proposed by North Shore along with the conclusions *supra*, the gas utility rate base for North Shore approved for purposes of this proceeding is $182,028,000. The rate base may be summarized as follows:

North Shore Rate Base (in thousands)

Description	Rate Base
Gross Utility Plant	$ 378,323
Accumulated Provision for Depreciation and Amortization	(148,561)
Net Plant	-$ 229,762
Additions to Rate Base:	
Materials and Supplies	1,539
Cash Working Capital	2,986
Gas in Storage	849
Budget Plan Balances	-
Unamortized Rate Case Expense	-
Pension Contribution	-
Deductions From Rate Base:	
Accumulated Deferred Income Taxes	(41,345)
Customer Advances for Construction	(748)
Cusomer Deposits	(2,860)
Cash Working Capital	(1,061)
Accrued Postretirement Benefits Other than Pensions ("OPEB")	(7,094)
Rate Base	$ 182,028

The development of the approved gas utility rate bases adopted for Peoples Gas and North Shore for purposes of this proceeding are shown in Appendices A and B, respectively, to this Order.

III. OPERATING EXPENSES

A. Overview

In the course of this proceeding, the Utilities have agreed to or accepted (for purposes of narrowing the issues) a total of 18 different adjustments to operating expenses proposed by Staff and the GCI. These uncontested issues are being considered in Section III(B) of this Order.

There are also five contested adjustments to operating expenses, based on Staff's proposed adjustments. Further, the GCI propose one contested adjustment to operating expenses that essentially is the same as one of Staff's proposals. All of the adjustments in dispute are being discussed in Section III(C) of this Order.

B. Uncontested Issues

1. Storage Expenses (Compressor Station Fuel Expenses) (PGL)

a) The Record

Peoples Gas witness Kallas accepted a GCI proposal to adjust Peoples Gas' expenses relating to compressor station operating fuel as long as it was recalculated based on updated fuel prices and fiscal year 2006 volumes, which resulted in a $953,000 adjustment (gross amount). PG-NGL Ex. LK-2.0, 14:294-309; PGL Ex. LK-2.3. GCI witness Effron agreed with that recalculated amount. GCI Ex. 5.0 at 12.

b) Commission Analysis and Conclusion.

The Commission finds that the proposed adjustment to Peoples Gas' expenses relating to compressor station operating fuel as revised, resulting in a $953,000 adjustment (gross amount) to Peoples Gas' operating expenses, is uncontested, reasonable and appropriate, and therefore approves it.

2. Distribution Expenses

a) Non-Payroll Expenses Inflation

(1) The Record

The Utilities proposed *pro forma* adjustments for expected 2007 inflation in non-payroll expenses of $3,084,000 as to Peoples Gas and $542,000 as to North Shore (gross amounts). PGL Ex. SF-2.0 at 27; NS Ex. SF-2.0 at 26. Staff witness Pearce proposed removing from each Company's operating expenses a pro forma adjustment to reflect 2007 inflation for non-payroll expenses. Ms. Pearce's recommendation was made for the reason that 83 Ill. Adm. Code 287.40 does not allow pro forma adjustments to the test year for the application of inflation factors in lieu of a particularized study of individual expense components and the Utilities' *pro forma* adjustment was not known and measurable. Staff Ex. 2.0 at 3-4. In order to narrow issues, the Utilities were willing to withdraw the proposed *pro forma* non-payroll expenses inflation adjustments given Staff and GCI contentions that their proposal was inconsistent with a rule provision regarding adjustments based on attrition and inflation factors and that the adjustments were insufficiently particularized to be known and measurable. NS-PGL Ex. SF-2.0 at 4-5:103 and fn. 2, 12-13, NS-PGL Exs. SF-2.3P, 2.7P, and 2.8P.

(2) Commission Analysis and Conclusion

The Commission finds that the withdrawal of the Utilities' *pro forma* non-payroll expenses inflation adjustments to be uncontested. Therefore, we approve the withdrawal.

b) Customer Installation Expenses (North Shore)

(1) The Record

Staff witness Pearce proposed an adjustment for North Shore only to remove from North Shore's test year operating expenses an amount which corrected an error from 2005. As Ms. Pearce explained, the correction of the error in 2006 caused the balance of expense in account 879 to be overstated by $175,000. Without Staff's adjustment, the test year amount for the account would not be reflective of normal operations. Staff Ex. 2.0 at 20. In order to narrow the issues, North Shore does not contest the removal of $175,000 of customer installation expenses (gross amount) proposed by Staff witness Pearce. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that the removal of $175,000 of customer installation expenses (gross amount) from North Shore's operating expenses is uncontested and reasonable. Therefore, the adjustment is approved.

c) City of Chicago Resurfacing Expenses (PGL)

(1) The Record

Peoples Gas, in direct testimony, proposed the *pro forma* adjustment for City of Chicago resurfacing expenses (which has rate base and operating expenses components) in the gross amounts amount of $1,400,000 (rate base) and $2,100,000 (expense). PGL Ex. SF-1.0 at 19, 30; PGL Ex. SF-1.1, Scheds. B-2.2, C-2.28. In rebuttal testimony, Peoples Gas updated its *pro forma* adjustments for City of Chicago resurfacing expenses providing for additional gross amounts of $4,397,000 (rate base) and $6,596,000 (expense). NS-PGL Ex. SF-2.0 at 12-13; NS-PGL Exs. SF-2.3P and 2.7P. Peoples Gas did not contest any further the adjustments by GCI that reduce Peoples Gas' rebuttal testimony updated figures by the gross amounts as to rate base of $1,080,000 and as to operating expenses of $1,620,000. NS-PGL Ex. 4.0 at 6.

(2) Commission Analysis and Conclusion.

The Commission finds that the *pro forma* adjustments for City of Chicago resurfacing expenses as updated in Peoples Gas' rebuttal testimony, subject to the revisions proposed by GCI and accepted by Peoples Gas in surrebuttal testimony, which reduce rate base (gross plant) by the gross amounts of $1,080,000 and operating expenses by $1,620,000 from the updated levels in Peoples Gas' rebuttal testimony, are not contested, reasonable, and appropriate. Therefore, these are approved.

3. Customer Accounts Expenses (Uncollectible Accounts Expenses)

a) The Record

GCI witness Effron recalculated proposed adjustments to Peoples Gas' and North Shore's operating expenses relating to uncollectible accounts expenses and Staff withdrew its proposed adjustment. North Shore and Peoples Gas witness Kallas responded that the Utilities were willing to accept the GCI proposals, only if these were recalculated based on updated fuel prices and fiscal year 2006 volumes, which would result in adjustments of $3,283,000 as to Peoples Gas, and $103,000 as to North Shore (gross amounts). NS-PGL Ex. LK-2.0 REV at 14-15; NS-PGL Ex. LK-2.3. GCI witness Effron agreed with these recalculated amounts. GCI Ex. 5.0 at 9-10.

b) Commission Analysis and Conclusion

The Commission finds that adjustments to Peoples Gas' and North Shore's operating expenses that reduce uncollectible accounts expenses by $3,283,000 for Peoples Gas, and by $103,000 for North Shore (gross amounts), are uncontested and reasonable. Therefore, we approve these adjustments.

4. Customer Service and Information Expenses

a) "Advertising" Expenses

(1) The Record

In his direct testimony, Staff witness Kahle proposed adjustments to the Utilities' Advertising Expenses for expenses that are of a promotional, goodwill or institutional nature (Staff Ex. 3.0, Schedules 3.2 N and P) on grounds that Section 9-225 of the Act prohibits them from being considered for the purposes of rates. Staff Ex. 3.0 at 10-11. In their rebuttal testimony, and in order to narrow contested issues, the Utilities accepted Mr. Kahle's adjustments. North Shore/Peoples Gas Ex. SF-2.0 at 5. As such, North Shore and PGL do not contest Staff witness Kahle's proposed adjustments to remove what he contended were promotional, goodwill, or institutional advertising expenses from operating expenses in the gross amounts of $308,000 as to Peoples Gas and $43,000 as to North Sore. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that the adjustments to Peoples Gas' and North Shore's operating expenses to reduce "advertising" expenses by $308,000 for Peoples Gas and by $43,000 for North Shore (gross amounts), are uncontested. These are each reasonable and thus, we approve the adjustments.

b) Dues and Memberships Expenses (PGL)

(1) The Record

In his direct testimony, Staff witness Kahle proposed adjustments to the Utility's Dues and Membership Expenses for membership dues associated with such organizations as the Chicago Club, the Mid-America Club and University Club of Chicago on account that these membership dues represent promotional and goodwill practices, Staff Ex. 15.0, Schedule 3.4 P, which Mr. Kahle considered to be unnecessary in providing utility service. In its rebuttal testimony, and in order to narrow contested issues, Peoples Gas accepted Mr. Kahle's adjustments. North Shore/Peoples Gas Ex. SF-2.0 at 5. As such, Peoples Gas does not contest Staff witness Kahle's proposed adjustment to remove certain membership dues in the gross amount of $14,000 from Peoples Gas' operating expenses. NS-PGL Ex. SF-2.0 at 4- 5.

(2) Commission Analysis and Conclusion

The Commission finds that the reduction in the gross amount of $14,000 in Peoples Gas' operating expenses, relating to certain membership dues is not contested and is reasonable. Therefore, we approve this reduction as stated.

5. Administrative & General Expenses

a) Civic, Political, and Related Activities Expenses

(1) The Record

In Schedules 1.9 P and N, Staff witness Hathhorn disallowed $80,000 and $11,000, respectively, in expenses allocated to the Utilities from Peoples Energy Corporation ("PEC") for civic, political and related activities on account that these expenses are ineligible for rate recovery according to Section 9-224 of the Act. The statute bars any expenses expended for political activity or lobbying from rates. Staff Ex. 1 at 12-13. North Shore and Peoples Gas do not contest Staff witness Hathhorn's proposal to adjust Peoples Gas' operating expense by $80,000 and North Shore's operating expense by $11,000 (gross amounts) due to the expenses being classified as civic, political and related activities. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's proposals to reduce Peoples Gas' operating expenses by $80,000 and North Shore's operating expenses by $11,000 (gross amounts) due to the expenses being classified as civic, political, and related activities are not contested and are reasonable. Therefore, these adjustments are approved.

b) Employee Recreation Expenses

(1) The Record

In Schedules 1.14 P and N, Staff witness Hathhorn disallowed $54,000 and $7,000 in payment of employee recreation expenses allocated to the Utilities from PEC for professional sporting event outings, picnics, and other social events not necessary to provide utility services. Staff Ex. 1 at 18. The Utilities do not contest Staff witness Hathhorn's proposed adjustments to remove expenses for employee recreation in the gross amounts of $54,000 as to PGL and $7,000 as to North Shore from operating expenses. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's proposals to reduce Peoples Gas' operating expenses by $54,000 and North Shore's operating expenses by $7,000 (gross amounts) for activities relating to employee recreation are uncontested and reasonable. For these reasons, we approve the disallowances in these amounts.

c) Corporate Rebill of Income Tax Penalties

(1) The Record

In Schedules 1.13 P and N, Staff witness Hathhorn disallowed $35,000 and $5,000, respectively, in payments of a federal income tax penalty allocated to the Utilities from PEC, on account that, generally, these types of penalties are not eligible for rate recovery as the charges were incurred for violation of a regulatory statute. Staff Ex. 1, at 17-18. The Utilities do not contest Staff witness Hathhorn's proposed adjustments to remove the rebilling of income tax penalties from Peoples Energy Corporation to the Utilities in the gross amounts of $35,000 as to Peoples Gas and $5,000 as to North Shore. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that Staff witness Hathhorn's proposed adjustments to remove the rebilling of income tax penalties from Peoples Energy Corporation to the Utilities in the gross amounts of $35,000 as to Peoples Gas and $5,000 as to North Shore are uncontested and reasonable. As such, these adjustments are approved.

d) Lobbying Expenses

(1) The Record

In his direct testimony, Staff witness Kahle proposed adjustments to the Utilities' Operating Expenses payroll associated with lobbying activities, Staff Ex. 3.0, Schedules 3.3 N and P, for reasons that such expenses are prohibited from rate recovery under Section 9-224 of the Act. In rebuttal testimony, and in order to narrow contested issues the Utilities accepted Mr. Kahle's proposed adjustments that would disallow lobbying expenses from rate base and operating expenses in the gross amounts of $12,000 (capitalized) and $67,000 (operating expenses) as to Peoples Gas; and $3,000 (capitalized) and $13,000 (operating expenses) as to North Shore. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed adjustments to remove lobbying expenses from rate base and operating expenses in the gross amounts of $12,000 (capitalized) and $67,000 (operating expenses) as to Peoples Gas and $3,000 (capitalized) and $13,000 (operating expenses) as to North Shore are not contested and are reasonable. Therefore, we accept and approve these adjustments.

e) Executive Perquisites Expenses

(1) The Record

Staff witness Pearce proposed an adjustment to remove from the test year executive perquisites for the Utilities. Based upon the Utilities' response to a data request, the executive perquisites included reimbursements to officers and high level executives for: auto allowances, supplemental life insurance, executive physicals, and flexible perquisite allowances to cover excess liability insurance, financial counseling and home office equipment. Ms. Pearce found these expenses to be discretionary and unnecessary for the provision of utility service. She further noted that the perquisites are awarded to a few top executives in addition to salaries and other benefits. Staff Ex. 2.0 at 19. The Utilities do not contest Staff witness Pearce's proposed adjustments to remove executive perquisites in the gross amounts of $170,000 as to Peoples Gas and $15,000 as to North Shore from operating expenses. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's proposed adjustments to remove executive perquisites from operating expenses in the gross amounts of $170,000 as to Peoples Gas and $15,000 as to North Shore are uncontested and reasonable. Therefore, we approve these adjustments.

f) Termination Costs (PGL)

(1) The Record.

Staff witness Pearce proposed an adjustment for Peoples Gas to remove termination allowances. Ms. Pearce explained that her adjustment removes from the test year expense which is not reflective of normal utility operations. Staff Ex. 2.0 at 20-21. The record shows that Peoples Gas does not contest Staff witness Pearce's proposed adjustment to remove a gross amount of $259,000 in termination costs from Peoples Gas' operating expenses. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed adjustment to remove a gross amount of $259,000 in termination costs from Peoples Gas' operating expenses is not contested and is reasonable in these premises. Therefore, the adjustment is approved.

g) Salaries and Wages Expenses

(1) The Record

North Shore and Peoples Gas proposed *pro forma* adjustments for salary and wage increases in the gross amounts of $3,576,000 for Peoples Gas and $431,000 for North Shore. PGL Ex. SF-1.0 at 26; PGL Ex. SF-1.1, Scheds. C-2.13, C-2.14; NS-Ex. SF-1.0 at 25; NS Ex. SF-1.1, Scheds. C-2.13, C-2.14. Staff witness Pearce proposed an adjustment for the Utilities for salaries and wages expenses to take into account a correction which the Utilities made to the underlying calculation for O & M union wage and nonunion merit increases for 2006 and O & M union wage and nonunion merit increases for 2007. Staff Ex. 2.0 at 21-22. The Utilities do not contest Staff witness Pearce's proposed adjustments, reflecting the Utilities' corrections to errors in their underlying calculations supporting their *pro forma* adjustments for salaries and wage increases, increasing operating expenses by the gross amounts of $124,000 as to Peoples Gas and $25,000 as to North Shore. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's proposed adjustments to the Utilities' salaries and wage increases, which increases *pro forma* operating expenses by the gross amounts of $124,000 as to Peoples Gas and $25,000 as to North Shore, are uncontested and reasonable. Therefore, we approve these adjustments.

h) Medical and Insurance Expenses

(1) The Record

GCI witness Effron proposed adjustments to operating expenses, that would reduce Peoples Gas' medical and insurance expenses by the gross amount of $866,000, and also would reduce North Shore's medical and insurance expenses in the gross amount of $83,000. The record shows that the Utilities do not contest these adjustments. NS-PGL Ex. SF-2.0 at 4-5.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed adjustments to operating expenses, reducing Peoples Gas' medical and insurance expenses by the gross amount of $866,000, and reducing North Shore's medical and insurance expenses by the gross amount of $83,000, to be uncontested and also reasonable. Therefore, we approve these adjustments.

i) Rate Case Expenses

(1) The Record

Initially, the Utilities proposed rate case expenses to be included in operating expenses, with the rate case expenses to be amortized over three years and with no adjustment to be made for carrying charge expenses. PGL Ex. 1.0 at 23; NS Ex. 1.0 at 22. And, in response to Staff and GCI's proposal that all rate case expenses be amortized over five years, Peoples Gas and North Shore stated that, if the five-year amortization period were to remain intact, they should be able to include the amortized amount in rate base. NS-PGL SF-2.0 at 6. In his direct testimony, Staff witness Griffin recommended a five year amortization period for rate case expenses instead of the three year period proposed by the Utilities. Staff Ex. 4.0 at 6-7. His five-year amortization period was based upon the average number of years between the most recent five rate cases while the Utilities' proposed three-year amortization period was based upon the average number of years between the most recent ten rate cases. Id. at 6. In order to narrow the issues, Utilities' witness Fiorella indicated that the Utilities would no longer contest the five-year amortization period. North Shore/Peoples Gas Ex. SF-4.0 at 5.

On the substantive matter, Peoples Gas and North Shore provided updated data on rate expense (actual amounts incurred and updated estimates for the remaining amounts) in their rebuttal testimony. NS-PGL SF-2.0 at 6-8; NS-PGL Exs. SF-2.9P and SF-2.9N. Based on his review, witness Griffin testified that Peoples Gas had supported $2,956,220 in total rate case expense and North Shore had supported $2,169,800 in total rate case expense. Staff Ex. 16.0 at 6.

Using a five-year amortization period for the supported showing of $2,956,220 in total rate case expense for Peoples Gas, and $2,169,800 in total rate case expense for North Shore, Mr. Griffin recommended a rate case expense for Peoples Gas equal to

$591,244 (Id. Schedule 16.1P, page 2 of 2) and recommended a rate case expense for North Shore equal to $433,960 (Id. Schedule 16.1N, page 2 of 2). To narrow the issues further, the Utilities did not contest Mr. Griffin's rate case expense for either Utility, North Shore/Peoples Gas Ex. SF-4.0 at 5, and further withdrew their proposal to include the unamortized portion in rate base (that Staff had opposed). Id. (Staff Ex. 16.0 at 2).

The Utilities do not contest the final revised proposed adjustments of Staff to operating expenses that reduce Peoples Gas' and North Shore's rate case expenses, as updated in rebuttal testimony, by the gross amounts of $680,000 and $690,000, respectively, with all rate case expenses to be amortized over five years, and excluding the amortized amount from rate base. The Utilities and Staff agree that the annual amortization for rate case expense for North Shore and Peoples Gas should be $433,960 and $591,244, respectively, based upon a five year amortization period with no unamortized balance in rate base.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed adjustments in Staff's rebuttal testimony to the amounts of the updated rate case expenses of the Utilities are reasonable and uncontested. Further, we find that Staff's and GCI's proposals to amortize rate case expenses over a five-year period without carrying charges, are uncontested and reasonable. For all these reasons, each of the adjustments reflected above are here approved.

j) Franchise Requirements Expenses (North Shore)

(1) The Record

In response to GCI witness Effron's direct testimony wherein he recalculated the proposed adjustment to North Shore's operating expenses relating to franchise requirements expenses, North Shore and Peoples Gas witness Kallas stated that North Shore was willing to accept the proposal, if it were recalculated based on updated fuel prices and fiscal year 2006 volumes, which results in a $584,000 adjustment (gross amount). NS-PGL Ex. LK-2.0 REV at 14; NS-PGL Ex. LK-2.3. Mr. Effron agreed with that recalculated amount. Effron Reb., GCI Ex. 5.0 at 11. No other witness disagreed.

(2) Commission Analysis and Conclusion

The Commission finds that the proposed reduction in North Shore's operating expenses in the amount of $584,000 (gross amount) is uncontested and it is reasonable. Therefore, we approve the reduction in just this amount.

k) PEC Officer Costs and Directors Fees

(1) The Record

In Schedules 1.12 P and N, Staff disallowed $702,000 and $100,000, respectively, to reallocate a reasonable portion of Peoples Energy Corporation ("PEC") officer costs and director fees to PEC, the Utilities' parent company at the time, rather than the Utilities. Staff Ex. 1 at 15-17. The Utilities accepted the adjustments in surrebuttal testimony in order to narrow the contested issues. NS-PGL Ex. SF-4.0 at 3. The Utilities do not contest Staff witness Hathhorn's revised proposed adjustments to operating expenses that removes Peoples Energy Corporation officer costs and directors' fees that were allocated to Peoples Gas in the gross amount of $702,000 and to North Shore in the amount of $100,000. NS-PGL Ex. SF-4.0 at 6.

(2) Commission Analysis and Conclusion

The Commission finds that Staff's revised proposed adjustments to remove officer costs and directors' fees that were allocated to Peoples Gas in the gross amount of $702,000, and to North Shore in the gross amount of $100,000, are uncontested and reasonable in these premises. Therefore, these adjustments are approved.

6. Taxes Other Than Income Taxes (Personal Property Taxes).

a) The Record

In rebuttal testimony, Peoples Gas revised its Taxes Other Than Income Taxes to include a proposed personal property taxes gross amount increase of $1,181,000, reflecting a court decision. NS-PGL Ex. 2.0 at 13; NS-PGL Ex. SF-2.8 P. No party contested this adjustment.

b) Commission Analysis and Conclusion

The Commission finds that the inclusion for Peoples Gas of an additional gross amount of $1,181,000 in personal property taxes in Taxes Other Than Income Taxes pursuant to a recent court decision is not challenged by any party and it is reasonable and appropriate under the circumstances. Therefore, this revision is approved.

7. Income Taxes (Interest Synchronization).

a) The Record

Initially, Peoples Gas proposed that its Interest Synchronization component of income taxes be calculated as $1,894,000, thus reducing income taxes by that amount. PGL Ex. SF-1.0 at 25; PGL SF-Ex. 1.1, Sched. C-2.8. North Shore proposed that its Interest Synchronization component of income taxes be calculated as $451,000, thus reducing income taxes by that amount. NS Ex. SF-1.0 at 24; NS Ex. SF-1.1, Sched. C-2.8. The rebuttal testimony of Utilities witness Fiorella, however, shows that the Utilities do not contest Staff's proposal that the Interest Synchronization component of income taxes should be recalculated, for purposes of final approved revenue requirement calculations, based on the final approved rate base times the weighted cost of debt. NS-PGL Ex. SF-2.0 at 4-5. Thus, all parties are in agreement on the matter. Staff Ex. 1.0 at 7 and Scheds. 1.5 P and 1.5 N; GCI Ex. 2.0, Sched. C-4.

b) Commission Analysis and Conclusion.

The Commission finds that Staff's proposal that, for purposes of final approved revenue requirement calculations, the Interest Synchronization component of income taxes should be recalculated based on the final approved rate base times the weighted cost of debt, is uncontested and is reasonable. Therefore, it is approved.

8. Meter Reading

a) The Record.

Staff initially raised a concern with the number of consecutively unread meters. In rebuttal testimony, however, Staff expressed general satisfaction with Peoples Gas' responses and suggested that Peoples Gas should provide quarterly updates (within 30 days after the end of each quarter) to the Director of the Energy Division and the Director of the Consumer Services Division of Staff, summarizing the number of consecutively unread meters without a reading for more than six months, or three months in the case of ERTed meters. Staff Ex. 23.0 at 20-23 & 25-26. Peoples Gas agreed to provide these reports. PGL-NS Ex. ED-3.0 at 3-4.

b) Commission Analysis and Conclusion.

No party opposes the agreement to provide the reports. As such, the proposal is adopted by the Commission.

C. Contested Issues

1. Storage Expenses.

a) Crankshaft Repair Expenses (PGL).

(1) Peoples Gas

Peoples Gas' test year operating expenses, as originally proposed, include $546,000 of repair expenses related to a failed crankshaft on the Manlove Field compressor. PGL Ex. LK-1.0 at 13. Given the unusual nature of this failed equipment, GCI witness Effron proposed that Peoples Gas be allowed to recover these expenses, but only on an amortized basis over a four year period. This means that the test year amount of $546,000 would be reduced by $410,000, i.e., to $136,000, in calculating the revenue requirement. GCI Ex. 2.0 at 32-33 and Sched. C-2 (Peoples Gas). In its responsive testimony, Peoples Gas accepted GCI's proposed adjustment. NS-PGL Ex. 2.0 at 4-5, & 12. This proposal, the Utility asserts, takes a reasonable and balanced view. It recognizes that Peoples Gas actually incurred these expenses in the test year and it further considers the unusual nature of the expense.

(2) Staff

Staff recommends a reduction to Peoples Gas' operating and maintenance expense ("O&M") in the amount of $136,000 to account for the non-recurring experience of the gas compressor repair, Staff Ex. 23.0 at 20, Staff's review of the circumstances demonstrate that the expense associated with compressor repair was a non-recurring expense, and all of the cost associated with that repair should be disallowed.

Staff's conclusion stems from the response to a data request which indicated that the expected life of the gas compressor was virtually indefinite and limited only by the ability to obtain replacement parts. Peoples Gas also indicated that over the past 20 years, it had never experienced a major repair of this magnitude. Id. at 32-33. And, Staff notes, Peoples Gas did not expect to incur major repairs with its large gas compressors in the foreseeable future. Id. at 33. Based on this information, Staff determined that the expense associated with the gas compressor repair was a non-recurring expense and that the expense should be disallowed. Id. at 34.

Staff notes Mr. Effron to agree that the compressor repair was a non-recurring item. Staff Ex. 23.0 at 19-20. And, he further indicated that a utility's actual expenses in a test year should be adjusted to reflect, among other things, the elimination of any abnormal or non-recurring items in order to reflect normal operations in the determination of revenue requirements. GCI Ex. 2.0 at 21. It is on these matters that Staff continues to recommend the removal of all of the O&M expense associated with the gas compressor repair. The valuation of that adjustment is the difference between Staff's recommendation of $546,000 and the $410,000 amount that Peoples Gas agreed upon with GCI, or $136,000. Staff Ex. 23.0 at 20.

Peoples Gas' main reason for disagreeing with Staff's proposal to disallow the compressor repair cost is the possibility that other non-recurring expenses will occur each year. According to Staff, however, it provided no support for this statement or any examples that Peoples Gas historic non-recurring expenses are in any fashion equivalent in magnitude to the costs associated with repairing the gas compressor. Therefore, Staff argues, its recommendation to disallow all of the expenses associated with the compressor repair on the basis of its non-recurring nature, should be accepted.

(3) Peoples Gas Response

Peoples Gas urges the Commission to allow recovery of these expenses, but only on an amortized basis over a four year period as proposed by GCI witness Effron. This means that the test year amount of $546,000 would be reduced by $410,000, i.e., to $136,000, in calculating the revenue requirement. GCI Ex. 2.0 at 32-33 and Sched. C-2 (Peoples Gas). Peoples Gas accepted GCI's proposed adjustment, and reflected that adjustment in its rebuttal and final revenue requirement calculations. NS-PGL Ex. SF-2.0 at 4, 5 & 12; NS-PGL Ex. SF-2.5P, column [D]; NS-PGL Ex. SF-2.6P, p. 3, column [E]; NS-PGL Ex. SF-4.3P, column [C]. According to Peoples Gas, the GCI's adjustment is reasonable.

In contrast, Peoples Gas observes Staff to propose a complete denial of recovery of the $546,000 and, as such, it would eliminate $136,000 in the revenue requirement calculation. Staff Ex. 11.0 at 32-34; Staff Ex. 23.0 at 19-20.

Peoples Gas maintains that Staff's proposal is far less reasonable in the situation, because it makes no attempt at balancing all of the factors. Staff simply denies all cost recovery of an expense that actually incurred. Moreover, Peoples Gas notes that Staff's proposal at this juncture is theoretically inconsistent with the position it takes regarding the matter of collection agency fees (where Staff contends that a level of that expense in the test year that is much lower than the level in prior years should be used in calculating the revenue requirement). Peoples Gas asks that the GCI's proposal, which it supports, be adopted. While Peoples Gas agrees that the repair of the gas compressor might be a single "non-recurring" event, it directs attention to the scope of Peoples Gas' distribution operations. Given the span of its operations, Peoples Gas argues, it is likely to experience different types of non-recurring events each year. North Shore/Peoples Gas Ex. SF-2.0 at 12.

Peoples Gas notes that there is no evidence to deny that the expenses were prudent, reasonable, and needed. Staff merely makes the point that the crankshaft failure was an unusual event, but that does not support denying recovery of these necessary expenses. Given the broad scope of Peoples Gas' operations, Peoples Gas argues, it is likely to experience different non-recurring events each year. NS-PGL Ex. SF-4.0 at 10.

(4) Commission Analysis and Conclusion

No party denies that the expenses were prudent, reasonable, and necessary. No party disputes that the repair expense occurred in the test year. Likewise, no party disputes that Peoples Gas' repair of the gas compressor was a non-recurring event. Taking these points together, the only question is whether the expense associated with this non-recurring event should be amortized or disallowed.

The Commission accepts GCI's proposal as fair and reasonable and finds that the Utilities should be allowed to recover $136,000 as the amortization amount for crankshaft repair expenses. This acknowledges that the expense did occur in the test year but is not expected to be a recurring event. It also recognizes that, given the vast scope of its operations, the Utility will, more likely than not, incur another kind of unusual expense. Taking these factors as a whole, the GCI's proposal is fair and appropriate.

Staff makes the point that the crankshaft failure was a very unusual event, but that is only one factor to be considered. Standing alone, it does not support denying all recovery of a prudent, reasonable, and necessary expense.

The amortized amount of $136,000 is fair and reasonable. It is recommended by GCI's witness and supported by Peoples Gas. GCI Ex. 2.0 at 32-33 and Sched. C-2 (Peoples Gas); NS-PGL Ex. SF-2.0 at 4, 5 & 12; NS-PGL Ex. SF-2.5P, column [D]; NS-PGL Ex. SF-2.6P, p. 3, column [E]; NS-PGL Ex. SF-4.3P, column [C]. Peoples Gas should be allowed to recover this amount.

b) Hub Services (PGL) (Addressed in Section V, below)

2. Customer Accounts Expenses (Collection Agency Fees)

a) North Shore/Peoples Gas

In calculating their revenue requirements, the Utilities substituted three year averages of the collection agency fees incurred in fiscal years 2003 through 2005 for the level in the test year. The fiscal year 2006 expense, they assert, was abnormally low due to the 2006 Gas Charge settlement. PGL Ex. SF-1.0 at 28; PGL Ex. SF-1.1, Sched. C-2.19; NS Ex. SF-1.0 at 26; NS Ex. SF-1.1, Sched. C-2.19. The effect of the settlement on the test year level of the fees was illustrated in the charts found on page 43 of the Utilities' Initial Brief.

b) Staff

In its Schedules 13.8 P and N, Staff disallows $1,770,000 and $76,000, respectively, and explains that these amounts represent each Company's proposed increase to normalize test year collection agency fees. According to Staff, the evidence reflects that the unadjusted test year expense is more likely to recur in the future than each Company's calculated increase. Staff Ex. 13 at 6.

Staff notes the Utilities to contend that actual 2006 collection expenses were lower than normal due to the gas charge settlement, and propose a normalization adjustment to account for the alleged impact of the Settlement Agreement on collection costs. PGL Ex. SF-1.0 at 28; NS Ex. SF-1.0 at 26. As indicated in the Order entered by the Commission on March 28, 2006, in Docket 01-0707, the Utilities entered into a Settlement Agreement with certain parties to resolve certain gas charge reconciliation proceedings. As part of the Amendment and Addendum to the Settlement Agreement, Staff notes that the Utilities agreed to forgive certain outstanding debt and not pursue collection of those amounts. In Staff's view, however, the Utilities' historical expense experiences and the current trend of post test year collection agency fees do not support their contention. Staff Ex. 1 at 8-9.

Staff observes the Utilities to state that not only are 2006 fees understated due to the Settlement Agreement, but the 2007 fees as well. PGL-NS Ex. LK-2.0 at 5. In Staff's view, however, the evidence shows that not only are the 2006 expense levels lower than the Utilities' request, the trend of lower collection agency fees than in prior years continues presently in 2007.On this point, Staff notes the Utilities to also explain that it is not uncommon for collections to take place several years after the bill is turned over to a collection agency.

Staff acknowledges that the Utilities may be correct in that at some unknown point in time in the future, its collection agency fees may eventually rise back to the pre-settlement level. Due to the lag in collections, and resulting fees incurred, Staff maintains that the 2006 and 2007 expenses are far below the 2004 and previous years' amounts. For the period of time the rates from the instant proceeding will be in effect, Staff contends that the Utilities' proposed average based on the 2003 through 2005 experience is inappropriate and overstates the expected collection agency fees going forward. Staff Ex. 13 at 10.

According to Staff, the Utilities disagree that their adjustment represents an attempt to collect costs incurred from the Settlement Agreement. North Shore/Peoples Gas Ex. LK-2.0 at 6. The Utilities' opinion, Staff notes, appears to be derived from its understanding of the agreement as evidenced by the claim that: "[T]his adjustment follows the intent of the agreement to eliminate all effects of the settlement….This is no different than any other adjustment to historical costs that are impacted by unusual activity." Id.

Staff notes that the Utilities' adjustments are not "any adjustment for unusual activity" as they were borne out of the Utilities' conduct and settlement of the issues in Docket 01-0707. The settlement represents, at least in part, the return to ratepayers of costs that the Utilities should not have recovered as prudently incurred costs. Thus, Staff argues, the Utilities' adjustment to "eliminate all effects of the settlement" with respect to uncollectibles has the effect, contrary to the intent of the settlement, to treat all costs as prudently incurred costs. Staff Ex. 13 at 10-11.

c) North Shore/Peoples Gas Response

Staff proposes that the Utilities be required to use the test year level in calculating their revenue requirements, resulting in proposed disallowances in the gross amounts of $1,770,000 and $76,000 as to Peoples Gas and North Shore, respectively. Staff Ex. 1.0 at 8-12, Sched. 1.8P, p. 1, Sched. 1.8N, p. 1. Peoples Gas takes issue with Staff's proposal as being unsound.

Staff claims that the test year levels are more likely to recur in the period in which the rates set in this case will be in effect than the three-year average used by the Utilities. Staff Init. Br. at 29. The facts do not support, and instead are contrary to, that claim.

The Utilities note Staff to rely on the test year level and the partial data available for 2007. Staff Init. Br. at 30. They point out, however, that the rates to be set in this proceeding will go into effect in 2008. Moreover, they observe that Staff is not being consistent in arguing that the rates to be set in this case will only be in effect for a short period. In this respect, Utilities observe that Staff took the position that rate case expenses should be amortized over a five-year period, on the grounds that that was a more likely interval until the Utilities' next rate case (and, in order to narrow the issues, the Utilities accepted that proposal). Id. at 24.

The evidence, the Utilities assert, strongly shows that the three-year average of fiscal years 2003 through 2005 is more likely to recur in the years in which the rates being set will be in effect. North Shore and Peoples Gas refer the Commission to the testimony of their witness Kallas, who stated that:

> Collection agencies are used to collect on older bad debt accounts. Therefore, fiscal years 2006 and 2007 amounts are artificially low due to the Utilities' agreement to not attempt to collect accounts that had been written-off and remained uncollected as of September 30, 2005. Accounts written off subsequent to September 30, 2005, however are not forgiven and have been and will be assigned to collection agencies for collection. This will result in collection agency fees being substantially more than experienced in the test year. A good estimate of the expected level of collection agency fees for the first year that the rates set in this proceeding will be in effect is the fiscal year 2003 through 2005 average used in Mr. Fiorella's proposed adjustment. In other words, the averaging of actual experience not affected by the agreement (i.e., fiscal years 2003 through 2005) is much more indicative of normal activity and cost for this account.

NS-PGL Ex. LK-2.0 REV at 5.

Staff's position here, the Utilities contend, which calls for using an abnormally low test year value here, is inconsistent with what Staff is recommending for normalizing the level of injuries and damages expenses, as will be discussed in Section III(C)(3)(a) of this Order, *infra*.

Further, the Utilities dispute Staff claims that the their position somehow is in conflict with the "intent" of the provision of the Gas Charge settlement under which they agreed to forgive certain debt owed in 2005 and not pursue collection of those amounts Staff Init. Br. at 30, 31. Nothing, they assert, could be more wrong. The uncontradicted evidence, the Utilities maintain, shows that the Utilities are not seeking to collect even one penny of the forgiven amounts, directly or indirectly. They are simply trying to include a normal level of collection agency fees in their revenue requirements used to set rates that will go into effect in 2008, and those fees do not in any way involve the forgiven amounts. NS-PGL Ex. LK-2.0 2REV at 6; NS-PGL Ex. LMK-3.0 at 3-4. For all these reasons, the Utilities argue, Staff's proposed adjustments are unwarranted and should be rejected.

d) Commission Analysis and Conclusion

On the basis of the evidence and arguments, the Commission approves the Utilities' adjusted collection agency fees levels and rejects Staff's proposed disallowances of $1,770,000 for Peoples Gas and $76,000 for North Shore. We are convinced that the Utilities' adjustments are appropriate in light of the abnormally low test year levels. We accept too, that the methodology they employ yields figures more likely to be representative of the expenses in the years in which the rates established in these proceedings will be in effect.

The Commission understands that there are purely tangential effects to the Settlement that have nothing to do with compliance of its terms. As such, the Utilities' 2006 and 2007 collection agency fees were (and likely should have been), vastly understated due to the Gas Charge settlement agreement. This is the only, albeit substantial, significance to be given to the Settlement in this instance and there is nothing improper in so doing. In other words, and contrary to what Staff would imply, the Utilities' proposal in this proceeding is in no way inconsistent with the terms of the Gas Charge settlement.

3. Administrative & General Expenses

a) Injuries and Damages Expenses

(1) North Shore / Peoples Gas

The Utilities incorporated their respective and appropriate levels of injuries and damages expenses in calculating their revenue requirements. Peoples Gas appropriately used the test year level, adjusted for a highly unusual credit recorded in fiscal year 2006 relating to a major claim that occurred in fiscal year 2002. PGL Ex. SF-1.0 at 19-21, 23 & 31; PGL Ex. SF-1.1, Sched. C-1, lines 13-14, Sched. C-2, line 30, and Sched. C-2.30. For its part, North Shore appropriately used its unadjusted test year level. NS Ex. SF-1.0 at 18-20; NS Ex. SF-1.1, Sched. C-1, lines 13-14; Sched. C-2.

(2) Staff

Staff witness Griffin proposes an adjustment to normalize injuries and damages expense. He observes Peoples Gas to have proposed an accrual of $6,192,000 (Staff Ex. 4.0, Schedule 4.4P, page 1 of 2) while North Shore proposed an accrual of $477,000. Id. Schedule 4.4N, page 1 of 2. Mr. Griffin explained that the Utilities' proposed accruals represented estimated amounts set aside for future claim payments. Id. at 8. Since the annual accruals can vary greatly from one year to the next, he considers it is more appropriate to normalize the expense for ratemaking purposes. Id. At the outset, Mr. Griffin calculated his normalized expense by examining the five year period from 2002 to 2006 and computing an average percentage of claims paid against the annual accrual. He then took that percentage and applied it against the accrual for 2006 Injuries and Damages.

In rebuttal testimony, Mr. Griffin revised his adjustment to account for an inadvertent error and, to include payments made in 2002 through 2006 for amounts under $100,000. Staff Ex. 16.0 at 6-7. His rebuttal position incorporated a corrected normalized adjustment presented in the testimony of the Utilities' witness Kallas in schedules 16.2P and 16.2N.

Staff notes Mr. Griffin to have explained that the difference between the Utilities' proposal and his proposal is significant, i.e., the difference between normalized and actual injuries and damages expense is 14% for Peoples Gas and 22% for North Shore. Staff Ex. 16.0 at 7.

Responding to the argument that Mr. Griffin gave no reason for choosing a five year period, i.e. 2002 through 2006, Staff would point out that the Commission used a five year period when examining injuries and damages expenses in the Ameren Illinois Utilities' recent rate cases. AmerenCILCO, AmerenCIPS, and AmerenIP electric rate cases, Docket Nos. 06-0070/06-0071/06-0072 (consol.) Order (November 21, 2006) ("Ameren Order"). In using a five year period for his analysis, Staff argues, Mr. Griffin was guided by the Ameren Order.

Staff notes the Utilities to assert that the year 2002 should be excluded from the analysis. According to Staff, however, the Ameren Order clearly establishes that the Commission will reject attempts by parties to exclude years which are not true outliers. While Utilities' witness Kallas that four years should be used rather than the five years Mr. Griffin uses, North Shore/Peoples Gas Ex. LMK-3.0 at 5, Staff maintains that there is no showing on the Utilities' part that year 2002 is "so out of the norm as to be considered [an]'outlier." Id. at 48-49.

For all these reasons, Staff argues, the Commission should adopt Staff's position that North Shore and Peoples Gas' Injuries and Damages expense should be $373,000 and $5,442,000 respectively.

(3) North Shore / Peoples Gas Response

Utilities maintain that Staff's proposed adjustments to injuries and damages expenses are unwarranted and arbitrary. Given the "relative closeness" of the expense, Utilities assert, there is no good reason to have normalized Injuries and Damages expense. North Shore/Peoples Gas Ex. LMK-3.0, p. 5. Nor did Mr. Griffin ever explain why he chose to use a five- year period to normalize the expense. Id. Further, they take issue with the methodology being applied for the normalization, to wit:

(1) calculate the five year average of the accruals for these expenses over the period of fiscal years 2002 through 2006,

(2) calculate the five year average of actual payouts over that period,

(3) divide the latter by the former to develop a percentage, and

(4) multiply that percentage times the fiscal year 2006 accrual to obtain the allowed level to be included in the revenue requirement. *See* Staff Ex. 16.0, Scheds. 16.2 P and 16.2 N.

Staff's witness, in his direct testimony, contended that the levels of injuries and damages expenses fluctuate and therefore should be normalized; proposed the above methodology to set the levels; and cited in the Ameren Order. Staff Ex. 4.0 at 8-9. He offered no reason for selecting a five year normalization methodology, as opposed to some other period, apart from that citation.

In the course of the proceeding, the Utilities' witness noted data errors made by Staff's witness, and pointed out that normalization was not warranted in this instance. NS-PGL Ex. LK-2.0 REV, at 9-11. While Staff's witness corrected his data errors, the only view that that he expressed was that the differences between his corrected averages and the Utilities' proposed levels, 14% as to Peoples Gas and 22% as to North Shore, were significant to have adjustments should be made. Staff Ex. 16.0 at 7. And, the Utilities note, he still did not provide any specific support for his choice of the five year period that yielded those percentages.

In surrebuttal, Ms. Kallas continues to disagree with any need for normalization, and again points out that Staff's witness still has not provided any specific support for his choice of a five year period. Further, she sets out that using either a four or three year periods would not support Staff's proposed adjustments, and that, in fact, a four year average would increase the levels of injuries and damages expenses included in the revenue requirements of both of the Utilities. Specifically, Ms. Kallas' testimony states that:

> Considering the relative closeness of this expense in the test year to the five year period chosen by Mr. Griffin, there is no good reason this expense should be normalized. Moreover, Mr. Griffin does not explain why he chose to use five years. If four years were used for Peoples Gas (fiscal years 2003 through 2006), it would indicate a higher "normalized" expense than actual fiscal year 2006. If a three year period is chosen for Peoples Gas, the "normalized" expense would almost equal the fiscal year 2006 accrual. The results are even more significant for North Shore where excluding fiscal 2002 in the calculation results in cash payments much higher than accruals. NS-PGL Ex. LMK-3.0 at 5.

In the Ameren Order, the Utilities observe, Staff looked at five years of data, but then discarded, in each instance, data from the one year that was considered unrepresentative, which then resulted in Staff's use of a four-year average. Here, Utilities point out, the fiscal year 2002 data that Staff uses is far different from the data for the other four years, Staff Ex. 16.0, Scheds. 16.2 P and 16.2 N, and, as Ms. Kallas shows in her testimony, excluding that one year would result in increases, not decreases, in the levels of injuries and damages expenses included in the revenue requirements of both Utilities. In short, the Utilities argue, the Commission should reject Staff's proposed adjustments because: (1) there is no significant reason to normalize these expenses; and (2) it is evident that Staff's choice of a five year period is arbitrary and unwarranted.

Utilities note Staff to claim that: "Since the annual accruals can vary greatly from one year to the next, it is more appropriate to normalize the expense for ratemaking purposes." Staff Init. Br. at 32. Any reasonable review of the actual levels, the Utilities contend, shows Staff's claim to be incorrect.

Staff's exhibits (Staff Ex. 16.0, Sched. 16.2 P, p. 2, lines 1-5, and Sched. 16.2 N, p. 2, lines 1-5) show that the levels for Peoples Gas and North Shore for fiscal years 2002 through 2006 were as follows:

Injuries and Damages Accruals

	Peoples Gas	North Shore
FY 2002	$9,185,000	$1,940,000
FY 2003	$5,147,000	$279,000
FY 2004	$5,124,000	$371,000
FY 2005	$6,502,000	$415,000
FY 2006	$6,192,000	$477,000

It is obvious, the Utilities assert, that the levels here shown do not support "normalization". It is only and precisely with Staff's inclusion of fiscal year 2002 data that the results would yield a large variance. Further, while Staff would claim no showing that fiscal year 2002 is an "outlier," Staff Init. Br. at 33, the data above plainly refute that claim. As such, the Utilities argue, there is no valid factual basis for Staff's proposed disallowances.

Noting Staff to rely on the Ameren Order to supports its use of the five-year period, Utilities point out that Staff never did provide the data that was used in that case to determine that normalization was appropriate in the first place. Moreover, in that instance, the Commission approved the AG's proposed use of a five year "average" of the payouts, and not the complex formula Staff applied here. Had Staff used that methodology, the Utilities observe, its proposed disallowances only would be smaller, because Staff would arrive at a level of $5,443,200 for Peoples Gas, not $5,242,000, and $545,000 for North Shore, not $373,000. *See* Staff Ex. 16.0, Sched. 16.2 P, p. 2, line 6, column (c) (divide by 5) versus line 9, and Sched. 16.2 N, p. 2, line 6, column (c) (divide by 5) versus line 9. Utilities maintain, however, that Staff's proposed adjustments should be rejected in their entirety, because it could not be clearer that normalization is not warranted in the first place, and that there is no valid reason given for Staff's employment of a methodology different from more generally used methodologies (the results of which would increase, not decrease, the expense levels included in the revenue requirements).

Finally, the Utilities would note that Staff's position, calling for normalizing the level of injuries and damages expenses, is theoretically inconsistent with its calling for the use of an abnormally low test year value for collection agency fees, as is being considered in Section III(C)(2) of this Order.

(4) Commission Analysis and Conclusion

We see from the record that depending on the time periods selected for normalizing, the results will either be fairly representative or skewed. While this Commission has accepted 5-year averaging in other cases, this is obviously not a hard and fast rule. It is always necessary, when gathering any periods of data, to further apply sound and reasoned judgment. Here, we are not persuaded by the correctness of using 5 years of data for reasons that one of these years, i.e., 2002, is clearly and unmistakably different from the others. Further, we perceive that something is inherently wrong in the selection when the results change so drastically when either 3 or 4 year data is considered. So too, we are not convinced that Staff's normalization required the complex methodology that it applied especially where plain averaging has been utilized in past cases. And, we see that the use of averaging also would have produced different results. For all these reasons, and because we are not persuaded that normalization was ever required in this instance, we reject Staff's proposed adjustments.

In the final analysis, the Commission finds that North Shore and Peoples Gas used the correct levels of injuries and damages expenses in calculating their revenue requirements. North Shore appropriately used its unadjusted test year level. Peoples Gas appropriately used its test year level, adjusted for a highly unusual credit recorded in fiscal year 2006 relating to a major claim that occurred in fiscal year 2002. No adjustments need be made.

b) Incentive Compensation Expenses

(1) Peoples Gas & North Shore

Peoples Gas and North Shore seek to recover $5,376,000 and $576,000, respectively, of incentive compensation program costs in their revenue requirements. Pearce Dir., Staff Ex. 2.0, Scheds. 2.2P and 2.2N. All these costs, they maintain, are prudent and reasonable in amount.

The Utilities seek to recover costs associated with several specific programs within their incentive compensation plans. Those programs include: (1) the Team Incentive Award plan; (2) the Individual Performance Bonus plan; (3) the Short-term Incentive Compensation ("STIC") plan; (4) officers' incentive compensation and bonuses charged by Peoples Energy Corporation to Peoples Gas and North Shore; and (5) long-term incentives, such as restricted stock and performance shares, covered by the 2004 incentive compensation plan. The evidence regarding these plans, the Utilities assert, shows that the expenses should be allowed.

<u>The TIA Plan</u>

The 2006 Team Incentive Award ("TIA") plan applied to non-officer, non-union employees. NS-PGL Ex. JCH-1.0 at 4. The performance measures under the TIA plan were 55% "financial" and 45% "operational". <u>Id</u>. at 4-5. The "operational" performance measures consisted of a 25% weighting for controlling O&M expenses and a 20% weighting for customer satisfaction criteria (10% based on the number of calls to the Utilities' call centers and 10% based on the ranking of the Utilities' Gas Charges compared with those of six other Illinois utilities.) <u>Id</u>. The Utilities demonstrated, in detail, that Staff's attempts to deny that 45% of the measures were operational are not correct, and Staff actually admitted that the Call Center metric benefits customers. NS-PGL Ex. JCH/FLV-2.0 at 5-7. Accordingly, while complete recovery of the entire $1,642,847 paid out, $1,502,584 by Peoples Gas and $140,253 by North Shore ($1,607,568 had been accrued, $1,465,444 by Peoples Gas and $142,124 by North Shore), under the TIA plan (NS-PGL Ex. LK-2.0 at 9 (dollar amounts)) is appropriate, at a minimum, Peoples Gas should recover the $1,009,240, and North Shore should recover the $94,024, that they paid out under the operational measures. NS-PGL Ex. JCH/FLV-2.0 at 7.

The IPB Plan

The 2006 Individual Performance Bonus ("IPB") plan also applied to non-officer, non-union employees. NS-PGL Ex. JCH-1.0 at 5. The performance measures under the IPB plan were not "financial", rather each division's senior management, with input from their managing staff, was responsible for calculating and awarding the IPB to their own employees, and, as the name of the plan indicates, the awards were based on individual performance. Id. at 5:95-103. Staff's unsupported speculation that the pool for this plan might somehow be "financial" was incorrect. NS-PGL Ex. JCH/FLV-2.0 at 9. The plan benefited customers by encouraging outstanding individual work performance. Id. NS-PGL Ex. JCH/FLV 2.2. Staff's objection that the Utilities did not establish specific dollar savings and other tangible benefits is not reasonable given that the pool and the awards are not tied to financial performance and the IPB awards went to 426 different employees in an average amount of $2,884.53. NS-PGL Ex. JCH/FLV-2.0 at 9-10. Accordingly, complete recovery of the entire $678,898 paid out, $625,791 by Peoples Gas and $53,107 by North Shore ($496,910 had been accrued, $464,408 by Peoples Gas and $32,502 by North Shore), under the IPB plan (NS-PGL Ex. LK-2.0 at 9 (dollar amounts)) is appropriate.

The STIC Plan

The 2006 STIC plan applied to senior management of Peoples Gas. NS-PGL Ex. JCH-1.0 at 6. The performance measures under the STIC plan were the same as under the TIA plan, discussed above. Id. at 6. There were no payouts as to fiscal year 2006, but that was for unusual reasons that are not expected to reoccur. Id. at 6. Accordingly, complete recovery of the entire $457,000 that was accrued, or, at a minimum, of the $306,953 that was accrued as to the operational measures, under the STIC plan (NS-PGL Ex. LK-2.0 at 9 (dollar amounts)), is appropriate.

The Affiliate Charges

The Peoples Energy Corporation charges for officers incentive compensation and bonuses to Peoples Gas and North Shore were generally based 37.5% on operational measures. NS-PGL EX. JCH-1.0 at 6. Accordingly, the entire $744,812 charged to Peoples Gas and the entire $165,811 charged to North Shore (Staff Ex. 2.0, Sched. 2.2P, p. 2, lines 12-13, and Sched. 2.2N, p. 2, line 12 (dollar amounts)) should be recovered or, at a minimum, 37.5% thereof.

Restricted Stock and Performance Shares

The restricted stock program was based on providing a competitive compensation package, not "financial" measures, while the performance shares program was based on "financial" measures. NS-PGL Ex. JCH-1.0 at 7. Accordingly, the entire $1,756,000 accrued (PGL only) (Staff Ex. 2.0, Sched. 2.2P at 2, lines 4-5 (dollar amount) should be recovered or, at a minimum, the amount of $1,529,000 as to the restricted stock program (Id. at line 4 (dollar amount)) should be allowed.

The Utilities contend that incentive compensation benefits customers through: increased customer satisfaction; improved service reliability; more efficient, lower cost operations that lead to lower rates over time when compared to less efficient operations; improved employee performance; enhanced ability to attract and to retain high-quality employees; and better employee productivity. In their view, these numerous benefits shown on record, satisfy any Commission requirement that incentive compensation not only be prudent and reasonable but benefit customers. By claiming that more is required in the way of specific dollar savings, Staff and GCI advance an unsupportable and inconsistent interpretation of the Commission's past tests. More egregiously, Utilities assert, their proposals would wrongly deny Peoples Gas and North Shore their right to recover all prudent and reasonable expenses. *See* Citizens 1995, 166 Ill. 2d at 121.

Further, the Utilities observe that the Commission has approved recovery of incentive compensation expenses in various other rate cases, including: In re Commonwealth Edison Co., Docket 05-0597, Order at 97 (July 26, 2006); In re Consumers Illinois Water Co., Docket 03-0403, Order at 14-15 (April 13, 2004); In re Illinois-American Water Co., Docket 02-0690, Order at 17-19 (August 12, 2003); and In re Commonwealth Edison Co., Docket 01-0423, Interim Order at 109-111 (April 1, 2002), and Order at 120-122 (March 28, 2003). The Utilities urge the Commission to do so here.

In the alternative, the Utilities maintain that the Commission should allow recovery of the specified operational and non-financial expenses, including, at a minimum: (1) Peoples Gas and North Shore should be allowed to recover $1,009,240 and $94,204, respectively, under the TIA plan; and (2) $625,791 and $53,107 under the IPB plan, respectively.

Incentive compensation, the Utilities assert, is a prudent expense. As their witness James Hoover explained, "[t]he Utilities compete in the labor market with other utilities and other businesses that offer incentive compensation.... [T]he programs are the product of careful decisions about what types and levels of incentive compensation are needed in order to attract and retain a sufficient, qualified, and motivated work force." NS-PGL Ex. JCH-1.0 at 3 & 8. Further, incentive compensation benefits a utility's customers "by making sure there are enough employees to perform needed work, by maintaining and improving the productivity and quality of work, and by reducing the expenses associated with recruiting and training new employees." Id. at 3-4. No witness, the Utilities note, has directly challenged this particular testimony (although two witnesses did claim that such customer benefits should be disregarded based on their understanding of the way that Commission has previously approached to the subject of incentive compensation).

The record contains further evidence of more specific, tangible customer benefits, the Utilities argue. For example, in their surrebuttal testimony, witnesses Hoover and Volante set out that the incentive compensation programs were a contributing factor in Peoples Gas and North Shore's reduction of O&M expenses below target levels. NS-PGL Ex. JCH/FLV-2.0 at 6.

According to the Utilities, no witness has challenged Peoples Gas' and North Shore's total compensation to employees, or, in particular, the incentive compensation portions, as imprudent or excessive. No witness testified that their incentive compensation programs and payouts thereunder are not prudent and reasonable from the perspective of managing their human resources. NS-PGL Ex. JCH 1.0 at 4. Indeed, it is clear that under the Staff and GCI positions, the amounts of incentive compensation that they challenge would not be at issue if the Utilities had paid the exact same amounts in total compensation as base pay. *See, e.g.*, Tr., 1196-1200. In light of this testimony, the Utilities maintain that their incentive compensation costs merit full recovery through rates.

(2) AG

The AG points out that the Commission typically disallows incentive compensation from utility revenue requirements except in those instances where the utility has demonstrated that its incentive compensation plan reduced expenses and created greater efficiencies in operations. In this instance, the AG contends, neither Peoples Gas nor North Shore have presented testimony persuasive enough to satisfy this criterion. GCI Ex. 5.0 at 10. The AG points out that both Staff witness Bonita Pearce and GCI witness Effron have recommended removal of incentive compensation costs from the 2006 test year of each Company. Staff Ex. 1.40 at 4; GCI Ex. 2.0 at 25-26; GCI Ex. 4.0 at 11.

The AG observes the Utilities witness to have testified that these programs serve "to attract and retain a sufficient, qualified and motivated work force." Staff Ex. 1.40 at 3. According to the AG, however, nothing in Mr. Hoover's rebuttal and surrebuttal testimony shows how the programs either reduce expenses or create the efficiencies that the Commission requires to support rate recovery. The AG states that the Commission made clear these standards for recovery of incentive compensation in the recent Nicor rate case, Docket 04-0779, and reaffirmed them in the 2006 Ameren Order. The AG considers the Utilities' descriptions of their incentive compensation programs and their vague assertions that such programs benefit ratepayers, as being inadequate to demonstrate that the incentive compensation plans have reduced expenses and created greater efficiencies in operations. In the AG's view, the Utilities have not satisfied the well established standards for the recovery of incentive compensation in the cost of service set out in the orders here cited.

In other words, the AG argues, the Utilities have failed to demonstrate that their incentive compensation plan confers upon ratepayers specific dollar savings or other tangible benefits. Thus, the AG contends that the incentive compensation expense should be eliminated from the cost of service. More precisely, Mr. Effron's recommendation that the incentive compensation expense be eliminated from the cost of service should be adopted, resulting in a reduction to Peoples Gas' test year operations and maintenance expense of $5,376,000, including the elimination of related payroll taxes. The reduction to North Shore's test year operations and maintenance expense is $576,000. GCI Ex. 5.0 at 11.

(3) Staff

Staff contends that none of the Utilities' incentive compensation costs should be reflected in rates. Staff Ex. 2.0 at 6–18 and Staff Ex. 14.0 at 3–20. Accordingly, Staff witness Pearce proposed adjustments to remove 100% of the costs of incentive compensation plans from operating expenses and rate base of North Shore and Peoples Gas. Staff Ex. 2.0, Schedules 2.2N and 2.2P, respectively. Staff's primary reason for its adjustment is that the incentive compensation plans are discretionary in nature and there has been no showing of demonstrated ratepayer benefit. Staff Ex. 14.0 at 4.

Staff notes, however, that if the Commission were determined to allow some portion of these expenses in rates, the least objectionable cost would be to allow costs related to that portion of the TIA Plan that is based on non-financial, i.e., operational measures that directly benefit ratepayers. In rebuttal testimony, Staff calculated an alternative for 10% cost recovery of the TIA Plan based on the number of calls to the call center component described by Utilities witness Hoover in his rebuttal testimony. Use of this methodology, Staff explains, would provide recovery in rates of $146,544 for Peoples Gas and $14,212 for North Shore Gas in 2006 test year operating expenses based on the TIA Plan expenses accrued for the test year. Id. at 19-20.

Further, and in response to the surrebuttal testimony of Utilities witnesses Hoover and Volante, Staff's calculated alternative to complete disallowance of all incentive compensation costs would be adjusted to $282,486 for Peoples Gas and $26,368 for North Shore (18.8% of actual payouts of $1,502,584 and $140,253 for Peoples Gas and North Shore, respectively), based on the final payout percentages and amounts awarded under the TIA Plan. North Shore/Peoples Gas Ex. JCH/FLV-2.0, lines 137-146. Staff's revised alternative is based on reduction of calls to the call center (the same methodology described in Staff's rebuttal testimony).

Staff does not believe that the Commission has ever approved recovery of incentive compensation costs on the basis of a utility's need to 'attract and retain a sufficient, qualified, and motivated work force', as it observes the Utilities to here assert. According to Staff, the only legitimate criterion for recovery of any portion of incentive compensation expense, based on prior Commission practices, is the demonstration of direct ratepayer benefits. As such, Staff sets out its arguments on each of the five Plans at issue.

In rebuttal testimony, Utilities witness Hoover asserted that the TIA Plan contained "non-financial" goals that directly benefit ratepayers such that 45% of the accrued costs of that plan should be recovered from ratepayers. In surrebuttal testimony, Mr. Hoover changed his methodology to assert that the percentage should be based on the amounts actually paid out under the TIA Plan instead of amounts accrued, as reflected in the test year. He then recalculated the “non-financial” percentage of incentive compensation expense and asserted that 67.2%, not of 45% of the TIA Plan should be reflected in rates, based on actual amounts paid out for 2006. NS-PGL Ex. JCH/FLV-2.0 at 7. The percentage of 67.2% includes the operational measures of (1) controlling O & M expenses (48.4%), and (2) calls to call centers (18.8%). Staff rejects this final alternative proposal to complete recovery of incentive compensation costs. Regarding the 25% factor for controlling O & M expenses, Staff notes that the Commission previously found this type of criterion to benefit shareholders rather than ratepayers, as noted by Staff witness Pearce. Staff Ex. 2.0, lines 323 – 335. With respect to the percentage of the payout that is based on calls to the call center, Staff explains that it revised its alternative to reflect the actual payouts and percentages.

Regarding the costs of the STIC Plan, Staff does not consider any of these accruals to be recoverable since they are based on measurements that primarily benefit shareholders, not ratepayers. For example, Staff observes that the awards to senior management (Chairman, President, and CEO) are entirely based on Earnings Per Share (“EPS”) and normalized operating income of Peoples Energy Corporation (“PEC”). Up to 50% of the awards to the remaining participants (the Plan only applies to officers) are based on EPS. The payment trigger for all STIC is the net income of PEC. In addition, Staff would note, STIC awards accrued during 2006 were not actually paid.

Under the Individual Performance Bonus Plan, Staff maintains that the bonus amounts are discretionary and not tied to any formula. NS-PGL Ex. JCH-1.0, lines 95–103. Staff observes Mr. Hoover to rationalize that since the awards were based on an employee’s individual performance (instead of the financial performance of the Utilities) and because the pool from which these awards were paid was a fixed dollar amount, these awards were not tied to the financial performance of the Utilities. Staff notes, however, that these awards are discretionary, which means they are able to be discontinued at any time after the test year. Additionally, Staff notes that the Utilities have not demonstrated that such awards are based on specific dollar savings or other tangible benefits to ratepayers, as required by the Commission in numerous prior proceedings. Finally, Staff observes from a response to a Staff Data Request, that the IPB Plan was only in place for 2006, i.e., the test year, and not any other year in the previous five fiscal years. This raises Staff’s concern that these plans are discretionary and may be changed or discontinued any time after the test year.

Staff points out that the Utilities failed to demonstrate any ratepayer benefits or cost savings that resulted from the other Plans, i.e., officers’ bonuses and incentive compensation expenses charged to Peoples Gas by an affiliate, as well as the restricted stock and performance shares programs. According to Staff, the Utilities simply rely on the bare assertion that these plans are not based on “financial measures”. NS-PGL Ex. JCH-1.0 at 6-8. As such, Staff maintains that these plans do not meet the criteria of cost savings and/or direct ratepayer benefit that the Commission has required in numerous prior rate cases. These plans, Staff contends, are based primarily on providing ‘a competitive compensation package’ and ‘to attract and retain a qualified work force’. NS-PGL Ex. JCH-1.0 at 7-8.

Staff maintains its position that none of the costs of incentive compensation plans should be reflected in utility rates for the reasons set forth in Staff witness Pearce's direct testimony and rebuttal testimony, to wit:

1) the Plans are largely dependent upon financial goals of the Utilities that benefit shareholders but not ratepayers;

2) in the future, the goals in the Plans may not be met and thus the Utilities would incur no cost (i.e., the payment of future awards is discretionary, but costs would be recovered in rates regardless); and

3) prior Commission orders support the disallowance of incentive compensation in these circumstances (as described in items 1 and 2 above, absent a demonstration of direct ratepayer benefits or savings.

Staff notes that several of the plans at issue contain a variety of performance measurement objectives. Staff is concerned that, for the future, management may assign different weights to these factors as they see fit. In other words, Staff believes that there is no guarantee that changes to the plans might occur going forward, and these might not provide any direct ratepayer benefit or savings. Staff Ex. 14.0 at 10. Accordingly, Staff urges the Commission to deny recovery of all incentive compensation costs in the instant proceeding.

(4) City-CUB

It is established policy, the City-CUB assert, that the Commission will allow the expense only if the utility has demonstrated that its incentive compensation plan has provided a tangible, quantified benefit to ratepayers, *i.e.,* reduced expenses and created greater efficiencies in operations. These requirements, they contend, were plainly stated in the order for the Nicor Gas rate case, Docket No. 04-0779. Further, the Commission reiterated its standards for the recovery of incentive compensation in the Ameren Order at 72.

Here, the City-CUB contend, the Utilities have failed to demonstrate their incentive compensation plan confers upon ratepayers specific dollar savings or other tangible benefits. Thus, they argue, the Utilities' *pro forma* operation and maintenance expenses should be adjusted to eliminate the incentive compensation expenses incurred in the test year. City-CUB explain that the reduction to North Shore test year operation and maintenance to eliminate incentive compensation is $576,000, and the reduction to Peoples Gas test year operation and maintenance to eliminate incentive compensation is $5,376,000, including the elimination of related payroll taxes. GCI Ex. 5.0 at 11.

(5) North Shore/Peoples Gas Response

Peoples Gas and North Shore seek to recover $5,376,000 and $576,000, respectively, of incentive compensation program costs (gross amounts, including capitalized expense amounts and operating expenses (including associated payroll taxes in Taxes Other Than Income Taxes)) in their revenue requirements. Staff Ex. 2.0, Scheds. 2.2P and 2.2N. These costs are prudent and reasonable in amount, they assert, and the Utilities should be allowed to recover them. Staff and GCI propose to disallow all of these costs. But, the Utilities argue, their proposals are erroneous and unreasonable, and should be rejected.

In the alternative, at a minimum, Peoples Gas and North Shore should be allowed to recover (1) $1,009,240 and $94,204, respectively, under the Team Incentive Award ("TIA") plan; and (2) $625,791 and $53,107, respectively, under the Individual Performance Bonus ("IPB") plan.

Like other large Utilities, Peoples Gas and North Shore include incentive compensation as part of their overall employee compensation packages. The Utilities maintain that they must offer incentive compensation in order to provide the competitive compensation package necessary to attract and to retain high-quality employees. It is on record that: "The Utilities and other large businesses seek to design employee compensation in order to attract and retain a sufficient, qualified, and motivated work force. Incentive compensation programs are a common method to help achieve those objectives." NS-PGL Ex. JCH-1.0 at 3. No witness, the Utilities note, has challenged this testimony.

Incentive compensation programs, the Utilities argue, were a contributing factor in Peoples Gas and North Shore's reduction of O&M expenses below target levels. NS-PGL Ex. JCH/FLV-2.0 at 6. They observe the Commission to have recognized that incentive compensation programs that reward employees for lowering operating costs benefit customers. *See* In re Commonwealth Edison Co., Docket 01-0423, Order at 129 (March 28, 2003); In re Consumers Illinois Water Co., Docket 03-0403 Order at 14-15 (April 13, 2004); In re Northern Illinois Gas Co., Docket 95-0219, Order at 27 (April 3, 1996). While Staff suggests that controlling and reducing costs do not count as benefiting customers, that is illogical and is inconsistent with the Commission orders upon which Staff relies. NS-PGL Ex. JCH/FLV-2.0 at 4-5. In the end too, Staff admits that measures tied to customer satisfaction directly benefit ratepayers. Staff Ex. 2.0 at 19.

According to the Utilities, incentive compensation plainly qualifies as a prudent expense. They assert that the programs offered are "the product of careful decisions about what types and levels of incentive compensation are needed in order to attract and retain a sufficient, qualified, and motivated work force." NS-PGL Ex. JCH-1.0 at 3 & 8. Further, incentive compensation for that same reason benefits a utility's customers: It is of record that a utility's attracting and retaining a sufficient, qualified, and motivated work force "benefits its customers by making sure there are enough employees to perform needed work, by maintaining and improving the productivity and quality of work, and by reducing the expenses associated with recruiting and training new employees." Id. at 3. Again, the Utilities point out, no witness challenged this testimony.

No witness, the Utilities observe, challenged Peoples Gas' and North Shore's total compensation to employees, or, in particular, the incentive compensation portions, as imprudent or excessive. No witness testified that their incentive compensation programs and payouts thereunder are not prudent and reasonable from the perspective of managing their human resources. NS-PGL Ex. JCH 1.0 at 4. Indeed, the Utilities note that it is clear from the Staff and GCI positions, that the amounts of incentive compensation that they here contest, would not be challenged if the Utilities had paid the exact same amounts of total compensation but had made the incentive compensation amounts part of base pay. *See, e.g.*, Tr. at 1196. In light of this testimony, the Utilities' maintain, their challenged incentive compensation costs merit full recovery through rates.

The Utilities maintain that incentive compensation benefits customers through: (a) increased customer satisfaction; (b) improved service reliability; (c) more efficient, lower cost operations that lead to lower rates over time when compared to less efficient operations; (d) improved employee performance; (e) enhanced ability to attract and to retain high-quality employees; and (f) better employee productivity. These numerous benefits, the Utilities assert, satisfy any Commission requirement that incentive compensation not only be prudent and reasonable but benefit customers. By claiming that more is required in the way of specific dollar savings, Staff and GCI advance an unsupportable and inconsistent interpretation of the Commission's past tests. And, their proposals would wrongly deny Peoples Gas and North Shore their right to recover all prudent and reasonable expenses. *See* Citizens 1995, 166 Ill. 2d at 121.

Additionally, the Utilities observe, there is nothing to suggest that they will not incur incentive compensation expenses going forward. Although there were no payouts during fiscal year 2006 under the STIC plan, that was for unusual reasons that are not expected to reoccur. NS-PGL Ex. JCH-1.0 at 6. Thus, the Utilities consider Staff's and GCI's concerns on this point are illusory and unsupported by the record.

Further, Staff and GCI propose to deny Peoples Gas and North Shore recovery of the incentive compensation portions of their total compensation expense without disputing that the Utilities' total compensation and the incentive compensation portions are prudent or reasonable in amount. Staff Ex. 2.0 at 6-18; GCI Ex. 2.0 at 25-26. The Utilities note GCI witness Effron to acknowledge that his testimony did not even address whether the Utilities' incentive compensation programs are prudent. Tr. at 1196. He further indicated that under his approach (which is the same as Staff's), it would not matter whether the Utilities' incentive compensation program helped to attract and retain the most qualified employees. Tr. at 1203. And, Staff witness Pearce made a similar admission. Staff Ex. 14.0 at 6. In the Utilities view, the proposed disallowances thus contravene the established principle that rates "must allow the utility to recover costs prudently and reasonably incurred." Citizens Utility Board v. Illinois Commerce Comm'n, 166 Ill. 2d 111, 121 (1995).

While Staff and GCI cite to certain Commission orders where recovery for incentive compensation was disallowed, the Utilities point out that the Commission has approved recovery of incentive compensation expenses in various other rate cases, including: In re Commonwealth Edison Co., Docket 05-0597, Order at 97 (July 26, 2006); In re Consumers Illinois Water Co., Docket 03-0403, Order at 14-15 (April 13, 2004); In re Illinois-American Water Co., Docket 02-0690, Order at 17-19 (August 12, 2003); and In re Commonwealth Edison Co., Docket 01-0423, Interim Order at 109-111 (April 1, 2002), and Order at 120-122 (March 28, 2003). The Utilities ask the Commission to do so here.

(6) Commission Analysis and Conclusion.

Before us on this issue are two conflicting views. While the Utilities assert that all parts of their incentive programs meet the standard for recovery, Staff, CUB and the AG would generally argue that none of these plans satisfy the test. As such, the Commission is put to the task of examining the record and applying its reasoned judgment informed by all of the relevant circumstances.

The record shows that there are as many instances where the Commission has approved incentive compensation as there are cases where such an expense has been denied. The main and guiding criterion is that the expense be prudent, reasonable and operate in a way to benefit the utility's customers. It is in this light that we consider the particulars of the programs, the amounts paid out, to whom and why, and what this all means to the Utilities' customers.

We agree with Staff that three of the five plans (STIC, Affiliate Charges, Restricted Stock & Performance Shares) fail to demonstrate the cost saving or other direct ratepayer benefit that we require. The remaining two plans, however, bring different concepts into focus.

Being a large utility means that management depends on the dutiful work performance of its employees. To motivate and maintain high standards, a utility may reasonably offer incentive compensation as the best way to match both employer and employee interests and to ensure quality work performance. And, when matters of customer service, customer satisfaction, the reduction of operating expenses, and the like is at hand, it is incumbent upon the Commission to take a close and considered view. It is on this basis that we turn our attention to the Utilities' non-executive TIA and IPB Plans.

<u>The TIA Plan</u>

This Plan applies to non-officer employees. As to its particulars, the Utilities' surrebuttal testimony effectively disputes Staff's claim that controlling O & M expenses should not count. It further shows that in the 2006 test year the aggregate actual O & M expenses were about $11 million below budget. Under the Plan, 25% of the measures were based on controlling these very expenses and we consider this as beneficial to ratepayers.

We further see that another 10% of the measures are tied to the number of phone calls made to the call centers. Even Staff recognizes the value of motivating this work. As such, Ms. Pearce admits that measures tied to customer satisfaction directly benefit ratepayers. Staff Ex. 2.0 at 19.

Further there is a measure of 10% associated with gas expenses and Gas Charges that we also believe should be counted. Finally, other unchallenged evidence of record confirms that 67.2% of the total payments were based on measures for controlling O & M expenses (48.4%) and call centers (18.8%). It is on this basis, that the Utilities derive their alternative proposal.

IPB Plan

The IPB plan is also a non-executive program that is aimed at encouraging outstanding individual work. It is uncontested that the awards are not based on financial performances. The record shows that the IPB awards went to 426 different employees, and were paid out in an average amount of $2,884.53. Taken together, the goal of the plan, the large pool of potential awardees and the wide-reaching motivational impact, make it more likely than not, that ratepayers will benefit from the race to excellence.

We do not share Staff's concerns as to possible changes or discontinuances of these Plans. The Commission finds that Peoples Gas and North Shore have demonstrated a steadfast commitment to incentive compensation in that they recognize the value, if not the necessity, of providing incentive compensation going forward. We would expect that if changes were to occur, these would equally go to the benefit of ratepayers.

In the final analysis, the Commission concludes that Peoples Gas and North Shore should be allowed to recover $1,009,240 for Peoples Gas, and $94,024 for North Shore for costs associated with the operational measures of the "TIA" plan.

Further, we allow the amounts of $625,791 for Peoples Gas, and $53,107 for North Shore, under the "IPB" plan, which is tied to individual performance and not to any financial measures. These costs are reasonable and prudent, and we perceive them to benefit the Utilities' customers. Together with all of the exceptions arguments, the Commission further rejects the GCI's alternative proposal on exceptions to have the Utilities' recovering under the IPB Plan be limited to the amounts accrued.

1. Invested Capital Taxes

a) North Shore / Peoples Gas

Staff and the Utilities agree that invested capital taxes need to be recalculated based on the final approved rate increases (the increases in base rate revenues) when setting the Utilities' final approved revenue requirements, and they agree over how to perform those calculations. NS-PGL Init. Br. at 54-55; Staff Init. Br. at 40.

The Utilities believe that, apart from an entirely speculative objection on the part of GCI, there is no dispute that invested capital taxes need to be recalculated based on the final approved rate increases (the increases in base rate revenues) when setting the Utilities' final approved revenue requirements, and that there is no dispute over how to perform those calculations. *E.g.*, NS-PGL Ex. SF-2.0 at 15; NS-PGL Exs. SF-2.13P and 2.13N; Staff Cross Exs. 1 and 2 (Fiorella).

b) City-CUB and the AG.

(The GCI parties rely on the same evidence and raise the same points in their respective arguments on brief. Thus, we consider them jointly).

The GCI parties observe that the Utilities adjusted the invested capital tax to recognize the increased operating income that will result from the proposed increased rates in this docket under the theory that an increase in operating income will in turn result in an increase to retained earnings and total capitalization, which is the base for the invested capital tax. GCI Ex. 2.0 at 34, citing PGL Ex. SF-1.0 at 24-25; NS Ex. SF-1.0 at 23. They point to the testimony of their witness Effron and his statement that these adjustments are inappropriate. They further note that Mr. Effron gave two reasons why the adjustments should be eliminated. GCI Ex. 2.0 at 34.

First, Mr. Effron observed that the Utilities have assumed, for purposes of this adjustment, that their entire rate increase requests would be approved by the Commission. Based on his experience, testifying in Illinois as well as other jurisdictions, Mr. Effron considered that such a scenario to be unlikely. Id. at 35. Second, he noted that the Utilities had not established with any reasonable degree of certainty that an increase to operating income will lead to an equal increase to retained earnings and capitalization. Id. For example, he indicated that an increase to operating income resulting from this case could lead to an increase in shareholder dividends. Id. And, to the extent that any additional earnings are paid out in dividends, there will be no increase to retained earnings as a result of the increase in operating income. Id.

The effect of Mr. Effron's adjustment, the GCI parties explain, is to reduce Peoples' pro forma taxes other than income taxes by $814,000 and North Shore's pro forma taxes other than income taxes by $50,000. GCI Ex. 2.0 at 35; Schedule C-4.[16] They propose that these adjustments should be adopted by the Commission.

c) Staff

Staff observes the Utilities to propose that the pro forma invested capital taxes ("ICT") in these cases is a derivative adjustment, to be calculated based on the approved additional operating income multiplied by the statutory rate of 0.8%. Staff Cross Ex. 1 and 2 (Fiorella). The Utilities contend that this approach is correct since the tax, which is based upon the Utilities' capital structure, was calculated based on the Company's pro forma 56/44 capital structure being maintained throughout the period of calculation. The Utilities maintain that application of this capital structure to the entire year's results contains an inherent dividend policy of maintaining the pro forma capital structure at all times, and thus explicit modeling of the dividend under these conditions would lead to the same results as already provided. Id.

Based on this evidence, Staff's Appendices A and B to this brief, pages 9 and 8 respectively for Peoples Gas and North Shore, contain updated calculations of the pro forma ICT adjustments. Staff agrees that this is a derivative adjustment and should be updated for the Commission's final conclusions in these cases. Tr. at 1123.

Staff maintains that the GCI's position and its opposition to the adjustment lacks merit. At the outset, Staff notes, GCI's first objection is that the Utilities' adjustments are based on receiving their entire rate increase request. AG Init. Br. at 25; City-CUB Init. Br. at 21-22. The Utilities have agreed, though, to limit and adjust the increase for ICT

[16] Mr. Effron's adjustment to the Utilities' pro forma expenses reflects the elimination of the adjustments as originally proposed by the Utilities rather than the amounts in the subsequent revised filings. He eliminated those original adjustments because those are the amounts included in the Utilities' pro forma statements of operating income used as the starting points in his analysis. GCI Ex. 2.0 at 35.

to the increase approved in the final Commission order. NS-PGL Init. Br. at 54. Therefore, GCI's objection based on this point is moot.

Staff observes that the GCI's second objection is related to its belief that the increase in income could be paid out in dividends. AG Init. Br. at. 25. According to Staff, however, this argument is contradicted by the record evidence indicating that the Utilities' ICT adjustment calculation is based on the Utilities maintaining their current capital structures, which reflects an inherent dividend policy of maintaining the pro forma capital structure at all times. Staff Init. Br. at 40; Staff Cross Ex. 2 (Fiorella). In Staff's view, thus, GCI is incorrect to argue that the Utilities have presented no evidence regarding their dividend policy; rather, GCI has chosen to reject or ignore it. As such, Staff asserts, GCI's position warrants rejection. City-CUB Init. Br. at 21.

Staff urges the Commission to calculate the final level of ICT, in the manner shown by Staff in Appendix A and B Corrected to its Initial Brief, at pages 9 and 8, respectively, based on the final approved rate increases or decreases.

d) North Shore / Peoples Gas Response

The Utilities note that GCI witness Effron proposed, on two grounds, to disallow the Utilities' *pro forma* adjustments reflecting the impacts on ICT of their proposed rate increases. First, he testified that the amounts for ICT included in the Utilities' proposed revenue requirements reflect the Utilities' proposed rate increases. *See* AG Init. Br. at 17; City-CUB Init. Br. at 21. In the Utilities view, this is a frivolous complaint. ICT are a derivative adjustment. Staff Init. Br. at 40. The correct way for a party to calculate a derivative adjustment is to start with its proposed positions on the merits of the relevant issues. The Utilities and Staff have made clear that the final amounts need to be recalculated based on the final approved rate increases.

The second ground, the Utilities observe, is nothing more than Mr. Effron's simple speculation that "it is entirely possible that an increase to operating income would lead to an increase in dividends. To the extent that any additional earnings are paid out in dividends, there will be no increase to retained earnings as a result of the increase in operating income." GCI Ex. 2.0 at 35. The Utilities point out that Mr. Effron provides no factual basis for his speculation, and, they assert, there is none. So too, they argue, Mr. Effron's proposal to deny recovery of ICT simply on the basis of such speculation is improper and cannot be considered by the Commission. *E.g.,* Ameropan Oil Corp. v. ICC, 298 Ill. App. 3d 341, 348 (1st Dist. 1998) ("speculation has no place in the ICC's decision or in our review of it."); Allied Delivery System. Inc. v. Illinois Commerce Comm'n, 93 Ill. App. 3d 656, 667 (1st Dist. 1981) ("The speculation indulged in by the Commission is clearly an unsatisfactory and unacceptable basis for its decision."); In re Commonwealth Edison Co., Docket 99-0117, Order at 105 (where the Commission states "we will not make an adjustment that is speculative"). (August 25, 1999).

The Utilities' assert that GCI's rank speculation about increases in dividends that might affect these taxes is unwarranted. The Utilities' proposed capital structure is uncontested. NS-PGL Init. Br. at 61. Thus, calculating these taxes based on different assumptions about dividends is not required. *See, e.g.*, Staff Cross Ex. 2 (Fiorella).

The Commission should calculate the final level of these taxes, in the manner which the Utilities and Staff agree is correct, based on the final approved rate increases.

e) Commission Analysis and Conclusion

The Commission accepts Staff's and the Utilities' proposal regarding the calculation of invested capital taxes. We are not persuaded by the bases for the GCI's proposed disallowances. There is no factual matter in dispute. In the end, there is no evidence in the record to support GCI's suggestion that an increase to operating income could lead to an increase in dividends. Nothing presented in the City-CUB's exceptions brief is persuasive on the matter.

2. Adjustment to Remove Non-Base Rate Revenues and Expenses (Schedule Presentation Issue)

Staff proposes to remove non-base rate revenues and expenses in presenting the Utilities' approved operating income statement. Staff emphasizes that this is a presentation issue, not a substantive proposal. The Utilities do not oppose this proposal, provided that it is only a presentation issue, and is implemented correctly. The Commission has considered Staff's proposal in preparing the applicable Schedules in the Appendix to this Order, and has formulated these Schedules as suggested by Staff.

D. Derivative Adjustments from Uncontested and Contested Issues

Various of the proposed rate base and operating expenses adjustments, when their full impacts are calculated, have derivative impacts on depreciation expenses, taxes other than income taxes, and/or income taxes, as shown in the Utilities', Staff's and GCI's respective Schedules, but no party has proposed any independent adjustments to these items. Accordingly, this Order, as to the foregoing items, need only make derivative calculations reflecting the approved adjustments.

E. Overall Conclusion on Operating Expense Statements

1. Peoples Gas

Based on the gas utility operating expense statement as originally proposed by Peoples Gas and the adjustments to operating revenues and expenses as summarized above, the total gas utility operating expenses for Peoples Gas approved for purposes of this proceeding are $365,321,000. The operating income statement may be summarized as follows:

Peoples Gas Operating Statement (in thousands)

Description	Approve d Operating Statement
Base Rate Revenues	$ 440,305
PGA Revenues	-
Coal Tar Revenues	-
Other Revenues	15,688
Total Operating Revenue	455,993
Uncollectibles Expense	39,155
Cost of Gas	-
Other Production	557
Distribution	61,846
Customer Accounts	35,996
Customer Service and Informational Services	363
Sales	1,355
Administrative and General	95,884
Depreciation and Amortization	59,203
Storage	9,993
Transmission	2,568
Taxes Other than Income	18,515
Total Operating Expense Before Income Taxes	325,435
State Income Tax	10,013
Federal Income Tax	61,236
Deferred Taxes and ITCs Net	(31,363)
Total Operating Expenses	365,321
NET OPERATING INCOME	$ 90,672

The development of the overall gas utility operating expenses adopted for Peoples Gas, for purposes of this proceeding, are shown in Appendices A and B, respectively, to this Order.

2. North Shore

Based on the gas utility operating expense statement as originally proposed by North Shore and the adjustments to operating revenues and expenses as summarized above, the total gas utility operating expenses for North Shore approved for purposes of this proceeding are $48,619,000. The operating income statement may be summarized as follows:

North Shore Operating Statement (in thousands)

Description	Approved Operating Statement
Base Rate Revenues	$ 60,978
PGA Revenues	-
Coal Tar Revenues	-
Other Revenues	1,639
Total Operating Revenue	62,617
Uncollectibles Expense	1,975
Cost of Gas	-
Other Production	170
Distribution	7,615
Customer Accounts	6,308
Customer Service and Informational Services	40
Sales	35
Administrative and General	18,523
Depreciation and Amortization	6,094
Storage	-
Transmission	95
Taxes Other than Income	2,034
Total Operating Expense Before Income Taxes	42,889
State Income Tax	9
Federal Income Tax	2,224
Deferred Taxes and ITCs Net	3,497
Total Operating Expenses	48,619
NET OPERATING INCOME	$ 13,998

The development of the overall gas utility operating expenses adopted for North Shore, for purposes of this proceeding, are shown in Appendices A and B, respectively, to this Order.

IV. RATE OF RETURN

A. Capital Structure

On September 30, 2006, the actual capital structure of North Shore was comprised of 40% long-term debt and 60% common equity and the actual capital structure of Peoples Gas was comprised of 43% long-term debt and 57% common equity. Staff Init. Br. at 41. For purposes of establishing rates in this proceeding, North Shore and Peoples Gas each propose imputed capital structures comprised of 44% long-term debt and 56% common equity. PGL-NS Init. Br. at 61.

Staff recommends utilizing the imputed capital structures proposed by North Shore and Peoples Gas. Staff, however, argues that under no circumstances should the Commission accept the Companies' proposed capital structures without also accepting Staff's proposed adjustments to the Companies' costs of common equity and debt.

The City-CUB witness incorporated North Shore's and Peoples Gas' proposed imputed capital structures in his calculation of the overall cost of capital. NS-PGL Init. Br. at 61.

The Commission has reviewed the record of this proceeding and finds that for purposes of establishing rates in this proceeding, a capital structure that is comprised of 44% long-term debt and 56% common equity should be used for both North Shore and Peoples Gas.

B. Cost of Long-Term Debt

1. Peoples Gas

There are no disputes concerning the cost of long-term debt. Peoples Gas and Staff agree that the appropriate cost of long-term debt to use for Peoples Gas in this proceeding is 4.67%. They also agree that certain adjustments to the actual embedded cost of debt are necessary to remove the incremental risk or increased cost of capital resulting from Peoples Gas' affiliation with unregulated or nonutility companies. Such adjustments are mandated by Section 9-230 of the Act as explained in Illinois Bell Telephone Co. vs. Illinois Commerce Commission, 283 Ill. App. 3d 188, 207 (1996).

Having reviewed the record here, we find that 4.67% is the cost of Peoples Gas' long-term debt for purposes of establishing rates in this proceeding, consistent with the requirements of Section 9-230.

2. North Shore

Similarly, there are no disputed issues and North Shore and Staff agree that the appropriate cost of North Shore's long term debt for this proceeding is 5.39%. The Commission has reviewed the record and finds that, for purposes of establishing rates in this proceeding, 5.39% is North Shores's cost of long-term debt, consistent with the requirements of Section 9-230 of the Act.

C. Cost of Common Equity

1. North Shore's and Peoples Gas' Position

Utilities witness Moul presented three market measures of the Utilities' cost of equity using the Discounted Cash Flow model ("DCF"), Capital Asset Pricing Model ("CAPM") and Risk Premium model. The Utilities state that because their stock is not publicly traded, the models must be applied to a proxy group of publicly traded natural gas utilities with risk profiles similar to the Utilities. NS-PGL Init. Br. at 66. For his proxy group, Mr. Moul's DCF analysis produced an estimate of 9.72%; his CAPM analysis produced results of 12.04%; and his risk premium analysis produced results of 11.44%. NS-PGL Ex. PRM-1.0 at 3. A simple arithmetic average of these three results produced a cost of equity estimate of 11.06%, which Mr. Moul believes to be a reasonable cost of equity for the Utilities and consistent with a comparable earnings analysis he performed to verify the reasonableness of his approach. Id. at 3-4.

a) DCF

In his DCF analysis, Mr. Moul used a quarterly version of the model. He estimated dividend yield by calculating the six-month average dividend yield of the utility sample, adjusting the average with what he describes as three generally accepted methods to reflect investors' expected cash flows, and then averaging the three adjusted values. In order to determine the investor expected growth rate, he evaluated an array of historical and forecast growth data from sources that he says are publicly available to, and relied upon by, investors and analysts. He focused on forecasts of earnings per share growth because empirical evidence supports it and because that is where investors actually place their greatest emphasis. He selected 5.00%, the approximate mid-point of the forecasts. Mr. Moul applied a financial leverage adjustment to his DCF result because DCF results are based on market prices of stock, which, according to Mr. Moul, imply a capital structure with more equity and less financial risk, but are applied to utility book values, which imply a capital structure with less equity and more financial risk. NS-PGL Init. Br. at 65-66.

The Utilities deny the criticism that Mr. Moul's DCF dividend yield was based on historical yields. Rather, they say he adjusted the six-month average yield of the utility sample "to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized." Id. at 66. Additionally, the Utilities state that although Mr. Moul reviewed historical data in considering the appropriate growth rate, he based his input on a mid-point of earnings per share forecasts. Id. at 66-67.

In response to Staff's objection to the use of an average of stock prices in the DCF model, the Utilities allege that Ms. Kight-Garlisch assumes a stock market with perfect efficiency that reflects the most recently available information each day. The Utilities aver that no evidence supports that hypothesis. The Utilities assert that a single day's price can produce an anomalous outcome because of the vagaries of the market. The Utilities claim that the short-term inefficiencies in stock prices are magnified when only a spot price is considered in the DCF return. Id. at 67.

The Utilities argue that because of these inefficiencies, analysts commonly use a six-month average dividend yield in the DCF model. According to the Utilities, that average provides a more representative estimate, adds stability to the result, better fits the long-term view of public utility rate-setting, and is more appropriate when rates are set for one or more future years. Id. at 68. The Utilities note City-CUB's assertion that an historical average ensures that the prices used in the DCF reflect all available information contained within the stock price. Id. (citing City-CUB Ex. 2.1). The Utilities maintain that rate-making is intended to set a return level appropriate for the period in which the rates will be in effect and the use of a single-day stock price can accomplish this objective only by coincidence. Id.

The Utilities further contend that thorough real-world investors do not purchase and sell stocks based exclusively on current prices, but also assess available historical and forecast information. The Utilities request that we reconsider our general concerns about the applicability of historical data in the market return models. In particular, they urge consideration of: 1) the lack of empirical foundation for the use of single-day spot data, which assumes a non-existent level of market efficiency; 2) the arbitrariness of setting returns based on "current" data that are nine months old; 3) what investors do in the real world, which is evaluate a stock's historical and forecasted performance in relation to its current price; and 4) the use of historical data in the DCF model, limited to the dividend yield, and adjusted to make it forward-looking. Id. at 69.

In addition to the overall concern with using a single day's data point in Staff's DCF analysis, the Utilities argue that anomalies in Staff's DCF results call into question the usefulness of Staff's DCF analysis in setting cost of capital in this case. The Utilities point out that the DCF results of three of the sample companies are below or too close to the cost of debt to measure the cost of equity reliably. The Utilities further observe that Staff's DCF analysis yielded a 5.91% ROE for Nicor, which they contend cannot be correct given the 10.51% ROE authorized by the Commission in North Illinois Gas Company's recent rate case. Petitioners also question NICOR's beta that emerged from Staff's DCF analysis. Moul Reb. NS-PGL Ex. PRM 2.0, 12-13.

According to the Utilities, the DCF model underestimates investor-required returns when a utility's stock prices diverge significantly from its book value. This occurs, the Utilities argue, because the investor-required return produced by the DCF model, which is related to the market value of common stock, is applied to the utility's book value capitalization in ratemaking. NS-PGL Init. Br. at 70.

Using formulas developed by Modigliani and Miller, Mr. Moul calculated a financial leverage adjustment of 52 basis points for this case. Id. As for Staff's objection that this adjustment has no basis in financial theory, the Utilities observe that Staff's own witness cites Modigliani's and Miller's conclusion that common equity costs are affected by debt leverage (to justify Staff's "credit quality risk" adjustment)

The Utilities charge that City-CUB witness Thomas actually wants commissions to regulate utility rates so that their stock prices always equal book value. They say that utility stock prices have been above book value for most of the past 50 years, yet commissions granted rate increases throughout this period. It is not conceivable, the Utilities maintain, that so many commissions have been so wrong for so long. Id. at 72.

They stress that the Pennsylvania Public Utility Commission has endorsed a financial leverage adjustment to the DCF model. Id. at 70.

The Utilities acknowledge past Commission decisions rejecting the financial leverage adjustment to DCF results, and they say they are not proposing to change this practice. Rather, in developing the market-required return, the Utilities urge us to take the increased financial risk of the book value capital structure into account when using the market-required rate of return on common equity. They request that we reconsider the financial risk adjustment, its theoretical underpinnings, and the evidence in this record that applying the DCF market results to book value capitalization will underestimate the investor's required return. Id. at 73.

Regarding growth rates used in the DCF model, the Utilities challenge City-CUB's claims that analyst forecasts are upwardly biased and that internal growth rates are better for calculating DCF growth rate. The Utilities say that concerns about analysts' conflicts of interest were resolved years ago by separating the research and investment banking services provided by Wall Street firms. They also allege that the studies City-CUB cite tend to report generalized findings and do not specifically suggest that utility growth rates are overstated relative to achieved growth. They further assert that the relationship of analyst growth forecasts to achieved growth is irrelevant to determining investors' true growth expectations. Id. at 74.

Moreover, the Utilities argue that internal growth rates measure the growth in the book value per share of a company, but book value also changes through the sale and repurchase of shares of stock. Book value per share, the Utilities contend, is not a correct focus of the DCF growth rate because stock does not trade at a constant market-to-book multiple. Id.

Mr. Moul states that the results of analytic models should be reviewed for fundamental reasonableness. Mr. Moul observed that three of Ms. Kight-Garlisch's DCF results for utilities in the sample approached and even fell short of the cost of debt. Such results, the Utilities argue, indicate that something seriously is wrong with Ms. Kight-Garlisch's application of the DCF model in this case. Id. at 75.

b) CAPM

The CAPM model determines an expected rate of return on a security by adding to the risk-free rate of return a risk premium that is proportional to the non-diversifiable, or systematic, risk of the security. This model requires three inputs to compute the cost of equity: (1) the risk-free rate of return; (2) a "beta" measure of systematic risk; and (3) the market risk premium derived from the total return on the market for equities minus the risk-free rate of return.

For the risk-free rate of return, Mr. Moul used historical and forecasted yields on 20-year Treasury bonds. He says long-term government securities are appropriate for the long-term horizon of utility investments. He selected a return, 5.25%, within the range of those yields. Ms. Kight-Garlisch relies on *short* term Treasury bills, but the Utilities aver that it makes little difference in this case due to the flat yield curve between long- and short-term Treasuries. NS-PGL Init. Br. at 79.

For the beta measurement of systematic risk, he used the average Value Line beta for his utility sample, adjusted to reflect the utility's book value capital structure used in rate-making. Mr. Moul believes Value Line betas cannot be used without adjustments in the CAPM, except when they are applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book value capital structure, he unleveraged and re-leveraged the Value Line betas for the common equity ratios using book values. He likens this is to the financial leverage adjustment he made in his DCF model. His "leveraged" beta was 1.00 for the utility sample (the average Value Line beta for his gas sample is 0.84), indicating that the group's systematic risk with book value capital structures is equal to the market's risk in general. In response to City-CUB's charge that the adjusted betas are biased, the Utilities counter that the Commission previously ruled that using unadjusted betas cause a downward bias in cost of common equity estimates. Id. at 80.

Mr. Moul developed the market premium of 6.60% by averaging historical and forecasted equity market performance derived from data sources routinely used by investors and analysts. For the forecast data, Mr. Moul specifically relied on the Value Line forecasts of capital appreciation and the dividend yield on 1,700 stocks. With these inputs, he calculated a CAPM cost of equity of 12.04%. Id. at 76-77)

c) Risk Premium

The Risk Premium model measures the cost of equity by determining the degree to which equity is more risky than corporate debt, and adding the compensation associated with that additional risk - the equity risk premium - to the interest rate on long-term debt. The Utilities acknowledge that this model has its limitations because analysts often cannot agree on the future cost of corporate debt and the measurement of the equity risk premium. NS-PGL Init. Br. at 81.

Mr. Moul estimated a 6.25% prospective yield on A-rated utility bonds, based on recent historical data and forecasts published by Blue Chip, which the Utilities claim is a widely utilized source that contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. For the equity risk premium, Mr. Moul compared market returns on utility stocks and bonds over various historical periods using the S&P Public Utility Index, and arrived at a 5.00% premium that includes an adjustment for the lower overall risk of the utility sample compared to the S&P index. Mr. Moul's Risk Premium model yields a rate of return for the Utilities of 11.44%, which falls between his DCF (9.53%) and CAPM (12.04%) results. Id. at 81-82.

Staff challenged Mr. Moul's use of historical public utility bond yields in his risk premium analysis because he did not demonstrate that they are equivalent to the A-rated bond yield, but the Utilities believe this would make no difference. However, Staff notes that the Commission has previously rejected the use of historical data in determining a company's cost of common equity. Staff Init. Br. at 68-71. As for Staff's claim that Mr. Moul did not provide quantitative support for adjusting the S&P Public Utilities equity risk premium downward to reflect the lower risk of the utility sample, the Utilities say Mr. Moul used informed judgment based on differences in risk fundamentals. Id. at 82.

Regarding City-CUB's assertion that Mr. Moul selectively chose the historical time periods to use, the Utilities counter that Mr. Moul selected fixed periods that cannot be manipulated as later financial data becomes available, and has used these same periods consistently in his work. They add that he gave greater emphasis to more recent data periods so that his equity risk premium would most reflect the market fundamentals most likely to exist for the future. Id. at 82-83.

2. Staff's Position

Staff estimates PGL's investor-required rate of return on common equity to be 9.70%. Staff applied the DCF and CAPM to the sample of gas utilities that Mr. Moul used in his estimate of return on common equity. Staff witness Kight-Garlisch believes that Mr. Moul's sample utilities are reasonable operating risk proxies for Peoples Gas and North Shore.

Ms. Kight-Garlisch's recommended cost of common equity for North Shore is 9.50%, using essentially the same analysis and arguments she used for Peoples Gas. However, Staff's revenue requirement recommendations, including its cost of common equity recommendation, indicate a level of financial strength commensurate with an AA credit rating for North Shore. Thus, the differences in financial strength between the two Utilities produced different cost of common equity recommendations.

For North Shore, Ms. Kight-Garlisch adjusted the results of her utility sample cost of equity estimate, 9.79%, downward by 29 basis points (the spread between A rated and AA rated 30-year utility debt yields). Thus, Ms. Kight-Garlisch's recommended cost of common equity for North Shore is 9.50%.

Staff emphasizes that the difference between the results of Mr. Moul's CAPM and DCF analyses (excluding his adjustments) and Staff's analyses is only 11 basis points. Staff claims that the major differences between the Utilities' and Staff's cost of common equity recommendations result from Mr. Moul's adjustments to the utility sample's cost of common equity. Mr. Moul adjusted his results because the market-value based common equity ratios of his sample are higher than the book-value based equity ratios for the Utilities. He also made an adjustment for flotation costs. Ms. Kight-Garlisch adjusted her utility sample cost of common equity to reflect her view of the lower financial risk of the Utilities compared to the utility sample.

Staff also criticizes the Utilities' use of historical data, arguing that historical data favors outdated information that the market no longer considers relevant over the most recently available information. Second, Staff argues that historical conditions may not continue in the future. (Staff Init. Br. at 68.)

a) DCF

Ms. Kight-Garlisch utilized a constant-growth quarterly DCF model. She measured the market-consensus expected growth rates with projections published by Zacks, Yahoo, and Reuters. The growth rate estimates were combined with the closing stock prices and dividend data as of April 25, 2007. Based on this growth, stock price, and dividend data, Ms. Kight-Garlisch's DCF estimate of the cost of common equity is 8.23% for the utility sample. Staff Init. Br. at 53.

Staff rejects City-CUB's opinion that the annual version of the DCF model is superior to the quarterly version. Staff notes that dividends are paid quarterly, not at year's end, putting money in investors' hands sooner. Moreover, in addition to its theoretical preference for the quarterly DCF model, Staff emphasizes that the Commission has explicitly rejected the annual DCF model in previous proceedings.

Staff also contests the Utilities' assertion that Staff's application of the DCF model is flawed because the results for some utilities in the utility sample are too low. Staff says its recommendation is based upon a representative sample, rather than any individual company's estimate, because estimates for a whole sample are subject to less measurement error. In Staff's view, eliminating utilities on the basis of their individual DCF results without regard to the effects of such action on the overall sample is improper, because it would defeat the purpose of using a sample. Staff states that removing the two utilities Mr. Moul complains about would reduce the sample to six, and, all else equal, a larger sample better mitigates the potential measurement error of the individual company cost of common equity estimates[17]. In addition, Staff asserts that Mr. Moul singled out utilities in the sample with "low" results. Staff Rep. Br. at 28-29.

b) CAPM

Staff states 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, Ms. Kight-Garlisch combined betas from Value Line and a regression analysis she performed. The average Value Line beta estimate was 0.87, while the regression beta estimate was 0.62. Staff Init. Br. at 53-54. Staff argues that the validity of its beta estimation methodology is not, as the Utilities suggest, a function of whether investors rely upon Staff's estimates, but whether the methodology is generally accepted. Staff claims it has regularly used its methodology and the Commission has consistently approved it. Moreover, it employs the same monthly frequency of stock price data as the widely accepted Merrill Lynch methodology.

According to Staff, Value Line and regression betas are estimates of the unobservable true beta, which measures investors' expectations of the quantity of non-diversifiable risk inherent in a security. Staff contends that the relative accuracy of the estimates is unknown. Staff also avers that other sources publish beta estimates for the utilities in the utility sample that are even lower than the regression beta estimates. Staff Rep. Br. at 26-28.

For the risk-free rate parameter, Ms. Kight-Garlisch considered the 4.83% yield on four-week U.S. Treasury bills and thirty-year U.S. Treasury bonds, each measured

[17] Staff states that if the Commission deems it appropriate to remove Nicor and Atmos Energy from the DCF analysis as outliers, the CAPM analysis would reduce its estimate of the cost of common equity from 11.34% to 10.91%. Staff Rep. Br. at 29-30.

as of April 25, 2007. Since the yields on the two Treasury securities were identical, her estimate of the risk-free rate is 4.83%.

For the expected rate of return on the market, Ms. Kight-Garlisch conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market was 13.46% for the first quarter of 2007. Inputting those three parameters into the CAPM, Ms. Kight-Garlisch calculated a cost of common equity estimate of 11.34% for the utility sample. Staff Init. Br. at 53-54.

Staff states that City-CUB fails to prove that DCF is a superior model to CAPM. Staff believes the use of multiple models improves the cost of common equity estimate. In Staff's view, Mr. Thomas erroneously attempted to correct the Utilities' CAPM analysis by using raw beta and the equity market risk premium from financial literature, instead of calculating a current equity market risk premium. According to Staff, empirical tests show that securities with raw betas lower than one tend to realize higher returns than the CAPM predicts, while securities with raw betas greater than one tend to realize lower returns than the CAPM predicts. Adjusting the raw beta estimate towards the market mean of 1.0, Staff asserts, results in a linear relationship between the beta estimate and realized return that more closely conforms to the CAPM prediction. Thus, Staff believes that Mr. Thomas' criticisms do not justify dismissal of CAPM as a useful model. Staff Init. Br. at 66-67.

c) Adjusted Results

Based on her DCF and risk premium analyses, Staff witness Kight-Garlisch estimated that the cost of common equity for the utility sample is 9.79%. To determine the suitability of that cost of equity estimate for North Shore and Peoples Gas, she compared the risk level of the utility sample to Peoples Gas and North Shore. Id. at 54. She concluded that Peoples Gas' financial strength is greater than the utility sample's A average credit rating, which indicates that Peoples Gas has less financial risk and thus less total risk than the sample. Since investors require lower returns to accept lower exposure to risk, she adjusted the 9.79% utility sample's investor-required rate of return downward to 9.70% (for the 9 basis point spread between A rated and AA- rated 30-year utility debt yields). Id. at 56.

Staff adds that it is appropriate to adjust the cost of common equity for Peoples Gas to reflect a credit rating of AA-, not only because the benchmark financial ratios that result from Staff's proposed revenue requirements are those of a company with an AA- credit rating, but also because Peoples Gas' affiliation with unregulated or non-utility entities lowered its credit ratings. On September 26, 2002, Standard and Poor's downgraded Peoples Gas to A- from AA-. Staff says the downgrade resulted from Peoples Gas' parent company's "increasing business risk with the growing share of nonregulated business." Id. at 56-57.

As previously discussed, Section 9-230 of the Act prohibits the Commission from including in rates the incremental risk or increased cost of capital resulting from a utility's affiliation with unregulated or non-utility entities. Staff argues that since Peoples Gas' A- credit rating is a function of its affiliation with unregulated or non-utility entities, the cost associated with that credit rating cannot be reflected in Peoples Gas' rates.

Staff claims that its downward adjustment to the cost of common equity of the utility sample addresses the requirements of Section 9-230. Id. at 57-58.

3. City-CUB's Position

City-CUB state that its witness, Mr. Thomas, principally based his estimate of the Utilities' required return on common equity Utilities on the results of a DCF analysis. That analysis estimates the return on equity the market demands for investment in a firm with the Utilities' level of riskiness – without what the City-CUB describe as the add-on adjustments that Mr. Moul used. Mr. Thomas used the CAPM to validate his DCF result. City-CUB Init. Br. at 27.

a) DCF

Mr. Thomas used an annual version of the DCF, asserting that the quarterly version overestimates the required rate of return. City-CUB state that other regulatory bodies have embraced the annual version. Id. at 29-30. City-CUB reject Staff's quarterly dividend adjustment because it focuses on working capital. Dividends are paid from retained earnings, not working capital. The authorized return on equity compensates investors for the risk of their utility investment. Id. at 27-28.

Purporting to minimize inconsequential disputes and to highlight the effects of the Utilities' adjustments, Mr. Thomas used much of the same data that Mr. Moul selected for his DCF analysis. He used the same proxy group of comparable utilities, as well as data sources and time periods from Mr. Moul's workpapers. He did not use Mr. Moul's sustainable growth rate, the quarterly adjustment to the expected annual dividend yield, or Mr. Moul's flotation and leverage adjustments. Mr. Thomas believes these elements are unreasonable and sources of upward bias. Id. at 27-28.

For his growth rates, Mr. Thomas used the internal growth rate that he claims recognizes the expected decline in dividend payout ratios, and the resulting disparate dividend and stock appreciation growth rates, for utilities in Mr. Moul's proxy group. City-CUB argue that using the internal growth rate obviates any need for consideration of Mr. Moul's proposed leverage adjustment, which they claim protects the Utilities' high market-to-book ratio.

City-CUB maintain that analysts' forecasts overestimate growth in dividends. Id. at 28-29. They describe the Utilities' counter-arguments as, first, utilities could be different, and, second, the accuracy of forecasts is irrelevant. City-CUB states there is no evidence that utilities are different. As for the second argument, City-CUB stress that the Utilities endorse Mr. Moul's subjective analyses because his aim is merely to identify "expectations," rather than market-required returns (reflected in the achieved returns that actually induced capital investments). Id. at 30-31.

City-CUB assert that Mr. Moul's growth rate input to his DCF model produces significant bias. They say he takes projected earnings per share growth rates taken from "optimistic analysts." Further, rather than simply using the average of those analyst growth rates, Mr. Moul made an upward adjustment, ostensibly to give consideration to the long-term projected growth rate in corporate profits. City-CUB argue that the projected growth in overall corporate profits generally outpaces regulated utility earnings. Id. at 41.

City-CUB also object to Mr. Moul's upward leverage adjustment to compensate for application of authorized rate of return to the book value of rate base, rather than to the market value of rate base assets. They argue that this adjustment rewards investors with extra compensation because the Utilities' market-to-book ratio is above 1.0. City-CUB states that Mr. Moul would achieve the higher return he advocates by applying an upwardly adjusted return on equity to the book value of the Utilities' shares, an adjustment equivalent to applying the unadjusted return on equity to the market value of all shares - an adjustment the Commission rejected in Docket No. 06-0070. They maintain that applying the Commission-determined return to the market, instead of to the book value of the capital devoted to providing utility service, would allow the Utilities to earn unlawfully on more than their authorized rate base. According to the City-CUB, the entire difference between Mr. Thomas' DCF estimate of 8.11% and Mr. Moul's 9.72% estimate is attributable to the effects of Mr. Moul's inappropriate growth and dividend yield inputs and his unlawful flotation and leverage adjustments. Id. at 41-42.

b) CAPM

City-CUB contend that the result of Mr. Thomas's DCF analysis (8.11%) was validated by the closely aligned result of his CAPM analysis (8.18%). Mr. Thomas used unadjusted betas in his CAPM analysis, rejecting beta adjustments to correct for a presumed reversion of the beta variable to a value of 1.0. City-CUB state that the distinctive nature of utility stocks undermines that presumption. They say that utilities with betas below 1.0 would have to make themselves more risky to validate the presumption. City-CUB note that the Utilities' proposals in this case demonstrate that they actually seek to minimize risk. City-CUB Init. Br. at 30-31.

City-CUB are not proponents of the CAPM, which Mr. Thomas employs only as a validator of his DCF analysis. City-CUB prefer the DCF model that relies more on objective market factors and less on subjective determinations of investors or the analyst. They claim that subjectivity, along with the serious theoretical and practical problems inherent in the CAPM, makes the DCF estimates more useful to the Commission. City-CUB Rep. Br. at 24.

A particularly relevant deficiency of the CAPM, City-CUB argue, is the deliberate exclusion of non-systematic risk factors from its return on equity estimation. They say that a fundamental premise of the CAPM methodology is that non-systematic risks peculiar to a specific utility, like the revenue assurance riders requested here, have no effect on its required return on equity. With regard to the revenue assurance riders, City-CUB claims that every witness actually rejects the premise that risks peculiar to a utility do not affect its required return on equity because it can be diversified away. City-CUB Rep. Br. at 24.

City-CUB opine that three main factors differentiate Mr. Thomas' and Ms. Kight-Garlisch's CAPM analyses. First, Ms. Kight-Garlisch, unlike Mr. Thomas, adjusted the beta estimate for the Utilities to effect a purported regression to the market beta of 1.0.

While Staff believes that this adjustment produces a result that is closer to the CAPM prediction, City-CUB say that Staff's argument simply assumes that the CAPM prediction is the appropriate return on equity estimate. Mr. Thomas says that the CAPM prediction is flawed and does not warrant equal weight with the DCF estimates, short of any biased modifications. Id. at 27.

Second, City-CUB and Staff selected different yield dates for the government securities that represent the risk-free return rate. Third, Ms. Kight-Garlisch computed her own expected market risk premium (the increment of return investors require for investing in the market as a whole). Mr. Thomas relied instead on the available body of empirical research on this issue, on the rationale that the expected general market risk premium is not unique to Illinois utilities or to this state. City-CUB claim that Staff's calculation of the expected market risk premium is approximately 72% above the premium established by the research literature and is 31% above the premium assumed by Mr. Moul. Id. at 34-35.

Staff acknowledges the differences between its and City-CUB's CAPM analysis, but maintains that its use of an adjusted beta and a current calculated market risk premium is consistent with the methodologies accepted by the Commission in numerous proceedings. Staff Rep. Br. at 31 (citing Dockets 06-0070/06-0071/06-0072 Cons., Order at 122, 143-145; Dockets 05-0071/05-0072, Order at 52-53; Docket 03-0403, Order at 32-33 and 42).

c) Risk Premium Model

City-CUB say that Mr. Moul performed a risk premium model estimate that is theoretically similar to the CAPM. They complain that Mr. Moul relies on only 75 years of data and selectively chooses time periods within that 75 years that produce an upward bias due to the strength of the US bond market during the 1980's. They say the Commission has rejected similar risk premium analyses in the past, and Mr. Moul has not justified a reversal of the Commission's position now. City-CUB Init. Br. at 44.

City-CUB note that Mr. Moul presented a comparable earnings estimate, 14.30%, as a check on his other estimates. They argue that the risk characteristics of utilities and unregulated firms are too dissimilar and that the extraordinary result of Mr. Moul's comparable earnings analysis should disqualify it from serious consideration. Id. at 44.

d) Criticisms of Other Analyses

City-CUB emphasize that Mr. Thomas' recommendation was based on DCF and CAPM results that were only marginally different and can viewed as mutually validating analyses. They claim Mr. Moul's biased adjustments push his recommendation far above the level of reasonableness. For this reason, the City-CUB suggest that the Commission's deliberations focus on the City-CUB and Staff recommendations. Specifically, they suggest focusing on the CAPM implementation issues that principally differentiate the recommendations of Staff and the City-CUB. Id. at 40.

City-CUB complain that Mr. Moul's final test of return on equity uses other commissions' return on equity determinations for utilities not shown to share relevant characteristics with the Utilities. They say he relies on this despite admitting that such subjective expectations might differ from the market-required return on equity. City-CUB assert that tracking commission orders does not lead to the actual market requirement. They say that that Mr. Moul wants investor expectations to mean subjective predictions instead of market requirements. Id. at 35-38.

City-CUB further assert that Mr. Moul and Ms. Kight-Garlisch averaged dissimilar return on equity estimates to produce their recommended returns on equity. They say that Staff's DCF and CAPM estimates differ by over 300 basis points while Mr. Moul's various estimates diverge by over 230 basis points. City-CUB states that different estimates cannot each be a correct measure of objective market factors. They assert that averaging them simply incorporates the errors in each measure into the recommended returns on common equity. Id. at 39-40.

4. All Parties - Market to Book Value

The Utilities adjust their market-based DCF and CAPM models for application to book value, by multiplying the result of a financial model by the utility's market-to-book-ratio. The Utilities state that the costs of equity produced by the financial models are based on the market value capitalizations of the utility sample. The sample's market value capitalizations contain more equity and less financial risk than its book value capitalizations used for ratemaking purposes. The Utilities argue that applying a market-based cost of equity to a book value capital structure yields a mismatch in the financial risks reflected in the two. If a return on equity based on a lower amount of financial risk is applied to a utility's book value capital structure, the utility's earnings will by definition be insufficient to allow the utility to achieve the authorized return.

Staff contends such adjustments are based on the incorrect notion that utilities should be awarded rates of return on common equity in excess of investor-required return whenever their market values of common equity exceed book values. Staff Init. Br. at 61. Staff says there are two possible explanations for how utility stock prices have come to exceed their respective book values: 1) the investor-required rate of return has fallen; or 2) expectations of future earnings have risen. Either way, Staff contends, if a utility's stock price grows to exceed its book value due to a decline in investors' required rate of return for that utility, a lower rate of return should follow. Id. at 62.

According to Staff, it is unwise to allow a utility to earn a rate of return on rate base equal to the product of its market-to-book ratio and the market required rate of return on common equity. That would produce an unending upward spiral as each successive increase in market value would lead to another increase in the allowed rate of return, which in turn, would lead to a further increase in market value. Staff Init. Br. at 64-65.

The Utilities contend that a market price above book value is necessary to maintain the financial integrity of shares previously issued and to avoid dilution when new shares are offered. City-CUB say there is no dispute that the Utilities currently enjoy market-to-book ratios far above 1.0, and assert that the premium reflected in that market-to-book ratio provides access to additional capital without diluting existing shares. City-CUB Init. Br. at 50.

While acknowledging the multiple theoretical reasons for a market-to-book ratio above 1.0, City-CUB underscore the one reason evident here - the Utilities' earnings in excess of their authorized return levels for several years since their previous rate case. In contrast, City-CUB argue, there is no evidence that incentive return awards from this Commission, rewards for excellent management, or market inefficiencies have affected the Utilities' market-to-book ratio. Accordingly, City-CUB maintain that Mr. Moul's leverage adjustment to perpetuate that ratio is unsupportable. City-CUB Rep. Br. at 29.

Nonetheless, Staff also asserts that Mr. Thomas' market-to-book-value analysis is based on the over-simplified premise that a utility should precisely earn its cost of capital on a continuing basis. Staff insists that many ratemaking practices (*e.g.*, deferred taxes and depreciation) can result in a utility's market value exceeding its book value. Thus, Staff avers that a market-to-book-ratio in excess of one does not necessarily mean the authorized rate of return is too high. Staff Init. Br. at 72-73.

5. Staff's Downward Risk Adjustment

Staff's DCF and CAPM market models produced costs of equity of 8.23% and 11.34%, respectively. The average of these two results, 9.79%, was adjusted for "financial risk." The downward adjustments in this case (29 basis points for North Shore and 9 basis points adjustment for PGL), purportedly reflect the lower financial risk of the Utilities relative to the utility sample. The adjustment involves a comparison of the Utilities' stand-alone S&P credit rating to the S&P credit ratings of the utilities in the sample. The Utilities object to Staff's financial risk adjustment. The Commission has accepted such adjustments in prior cases.

Staff emphasizes that the Utilities' current S&P credit ratings are affected by their non-regulated affiliations and are, therefore, not reflective of their stand-alone risk. Staff asserts that since the Utilities' implied forward-looking credit ratings are higher than the average A S&P credit rating of the utility sample, a downward adjustment is necessary. Staff argues, in essence, that because the bond ratings of the Utilities are affected by their non-regulated affiliations, the Commission must look beyond the actual bond ratings to the riskiness of the underlying regulated entities. Staff maintains that it performed a comprehensive analysis and the financial risk of the Utilities is less than that of the utility sample. Staff Rep. Br. at 22-23.

The Utilities say there is no evidence that Staff reviewed and confirmed the similarity of the Utilities to the proxy group on many of the parameters Mr. Moul used to select and confirm his sample. By singling out credit rating and ignoring the other comparability parameters Mr. Moul considered, Staff can misleadingly claim that the risks of the proxy group do not "average out" and therefore fail to provide a reasonable basis for the Utilities' market models. However, the Utilities assert, while the utility sample reflected a different average credit rating than the Utilities, that difference was offset by differences in other financial parameters that indicate the Utilities have more risk than the proxy group. NS-PGL Rep. Br. at 57.

Moreover, the Utilities suggest, if Mr. Moul's proxy group was not sufficiently comparable with respect to credit rating, it may not have been comparable with respect to other factors - or, differences in other factors could have offset the lack of comparability on credit rating. NS-PGL Init. Br. at 83-85. The Utilities argue that if Staff did not believe Mr. Moul's proxy group reflected comparable risk (operational and/or financial), Staff should have assembled a different proxy group that it believed "balanced" both operational and financial risk as compared to the Utilities.

The Utilities charge that Staff's financial risk adjustment is inconsistent with its position on Mr. Moul's financial leverage adjustment. In each case, the Utilities assert, the witness adjusted the Utilities' rates of return to reflect their capital structures, in particular their debt leverage. Thus, Staff cannot have it both ways, ignoring the differences in capital structures reflected by its market model results and the Utilities' book value capital structures, while adjusting another market models' results to reflect the Utilities' debt leverage as represented by their credit ratings. Id. at 85-86.

Staff responds that Mr. Moul's opposition to the use of credit ratings in evaluating the reasonableness of a cost of equity estimate is inconsistent with his own use of credit ratings and leverage ratios to evaluate a sample used to estimate cost of common equity. Further, Staff argues, the Commission should not ignore the financial strength implied by the benchmark ratios in comparing the risk of Peoples Gas and North Shore versus the proxy sample. Staff maintains that since the implied forward-looking credit rating is higher than the average A credit rating of Ms. Kight-Garlisch's sample, a downward adjustment is necessary to reflect the basic tenet of financial theory that the investor-required rate of return is lower for investments with less exposure to risk. Staff Init. Br. at 60-61.

The Utilities also complain that Staff's financial risk adjustment contains an unexplained differential in the treatment of North Shore and Peoples Gas, despite the fact that the two utilities have had the same credit ratings for at least the past five years. According to the Utilities, if there should be any disparate treatment between the two, there should be an upward adjustment of North Shore's return on equity to reflect its small, stand-alone size. Id. at 86.

Staff opposes increasing North Shore's cost of common equity to reflect it smaller size. Staff avers that if a size-based risk premium exists for utilities, it should be based on the size of the Utilities' parent company, Integrys. Although North Shore raises its own debt, it obtains common equity financing from its parent company. Staff observes that Integrys has a market capitalization of over $3.87 billion and being a part of a much larger organization should enhance the ability of North Shore to access the common equity market on reasonable terms. The Commission, Staff points out, has rejected a size-based risk premium in many cases, including Docket No. 03-0403. Staff Rep. Br. at 23-24.

6. Returns Approved for Other Utilities

The Utilities argue that the Commission should consider other rates of return recently allowed for other gas utilities in Illinois and elsewhere. The Utilities cite fifty-four cost of common equity decisions for electric and gas utilities for 2006 and contend that they demonstrate the insufficiency of Staff's and City-CUB's recommendations. The Utilities state that rates of return on equity awarded to gas utilities in the United States averaged in the mid-10% range in 2006, and 10.35% through March 2007. They add that Value Line forecasts the natural gas utility industry to earn 11.5% in 2007 and 2008. Also, in Nicor Gas' last rate case, the Commission approved a 10.51% return. NS-PGL Init. Br. at 91. The Utilities note that City-CUB's recommended returns on equity are far below any return authorized by this Commission for a gas utility in the last thirty years, and so far below any return awarded to a gas utility by any state commission in recent years, that they do not merit serious consideration. NS-PGL Rep. Br. at 52.

Staff replies that Mr. Moul failed to address critical factors that influenced the allowed returns in the fifty-four proceedings. Staff says Mr. Moul did not identify the relative risk, as exemplified by credit rating or any other metric, of each of the pertinent utilities. Nor did he identify the capital structure or the amount of common stock flotation cost adjustment, if any, included in those decisions. Without such data, Staff argues that any comparison of return recommendations is useless. Staff Rep. Br. at 30.

Moreover, Staff contends, given the financial strength implied by the Utilities' forecasted financial ratios, it would expect the Utilities' required return on common equity to be considerably lower than average. Staff notes that its recommendations of 9.5% for North Shore and 9.7% for PGL are below the 10.49% average allowed by U.S. regulatory commissions in 2006, while the Utilities' return request of 11.06% is above that average. In any event, Staff says, the Commission has rejected this type of comparability in ComEd's most recent delivery services docket. Id. at 30-31.

7. Effect of the Utilities' Proposed Riders

Staff and City-CUB argue that if the Commission approves proposed Riders VBA and UBA, the Utilities' authorized rates of returns should be reduced to reflect the resulting reduced risk. In particular, Staff asserts the riders would reduce operating risk, which the Utilities acknowledge is part of investment risk. Staff reasons that since investor-required rate of return is lower for investments with less risk exposure, the riders should reduce rate of return. Staff avers that because the riders would transfer risk from the Utilities to ratepayers, none should be approved without compensation through lower authorized rates of return. Staff Rep. Br. at 26.

City-CUB attempt to quantify the financial risk impact of the riders by comparing them to the value of weather insurance policies the Utilities' corporate parent previously purchased to protect shareholders against earnings shortfalls in the event of significantly warmer weather than forecasted. Mr. Thomas valued the insurance protection by noting, first, that Peoples Gas shareholders were willing to pay a significant premium for the lower level of revenue assurance (as compared to the proposed riders) the weather insurance policy provided, and, second, that the payout would have provided a benefit equal to an after-tax return on equity benefit of 0.695% to Peoples Gas and 0.660% to North Shore. City-CUB Init. Br. at 46-47.

According to the City-CUB, because the protection provided by the policy was significantly less favorable to Peoples Gas than the riders would be, Mr. Thomas' derived estimate of the return on equity effect is very conservative. They say they confirmed this with a "backcast" of the effect of Rider VBA alone, had it been in effect for the single year 2005. They contend that the $4.47 million net benefit from the maximum policy payout pales in comparison to the $30 million that PGL could have realized from only one of the proposed riders. Id. at 47.

The Utilities criticize Mr. Thomas' analysis, which takes the maximum payout under one of the policies, deducts the premium paid, and treats the net payout as the value of the policy. They argue that the value of an insurance policy must reflect the probability of the payout. They say the value of the policy is therefore represented by the premium amount, which should equal the average expected payout less administrative costs.

In addition, the Utilities assert that Mr. Thomas did not consider that the weather insurance policy required Peoples Gas Energy Corporation to pay an additional premium if weather was somewhat colder than forecasted (akin to Rider VBA requiring refunds). They say that under Rider VBA there is "payout" to the Utilities if weather is warmer than forecasted, but the "payout" is to ratepayers if weather is colder. NS-PGL Init. Br. at 89-90.

More generally, the Utilities reply that there is no evidence that approval of the riders would have any impact on investor-required return, theoretical or otherwise. They say Staff and City-CUB simply presume an impact and suggest methodologies to calculate the reduction. NS-PGL Init. Br. at 86-87. The Utilities state that under the financial theory upon which the cost of common equity is based, investments are valued on a long-term basis. They say the DCF model expressly assumes a growth rate that approaches infinity, and the CAPM expressly ignores company-specific, unsystematic, risks. They insist that the investor-required cost of capital for a gas utility is not affected by variations in usage due to weather and therefore is the same either with or without a VBA rider. Id. at 87.

Additionally, the Utilities claim, such riders do not affect the investor's required return because weather and uncollectibles are not business risks that investors take into account. However, even assuming that the riders would affect the cost of equity, the Utilities say no evidence supports Staff's assumption that approval of the proposed riders would cause S&P to increase the Utilities' business profile score a full notch to 2. Id. at 89.

The Utilities further assert that the riders would protect shareholders and ratepayers alike from the risk of variations from the "normal" assumptions for weather and uncollectibles used for ratemaking purposes. The Utilities also claim that the majority of Utilities in the utility sample used by all three cost of capital witnesses have similar cost recovery mechanisms and their financial data reflect that fact. They thus emphasize that the Missouri Public Service Commission recently refused to adjust a gas utility's authorized rate of return for precisely this reason. Id. at 88.

Indeed, the Utilities propose that rates should be *increased* if the riders are rejected, based on the financial parameters of the utility sample. Staff responds that the Utilities have no riders now, yet have the same level of operating risk as the Gas Sample, which includes Utilities that have some of the tracking mechanisms the Utilities have requested in this proceeding. In Staff's view, approving some or all the riders would reduce the Utilities' operating risk below that of the utility sample, which would further lower the Utilities' cost of common equity. City-CUB assert that the scope and economic effect of the other utilities' tracker mechanisms have not been compared to the Utilities' proposed riders. They say at least one of the proxy utilities has no mechanism like the riders here, while another has what can more accurately be called a conditional rate design element than a revenue assurance rider.

City-CUB charge that the Utilities make a new argument in their Initial Brief that the riders are "risk neutral" because they "protect shareholders and customers alike." They assert that the additional revenues identified by the Utilities' "backcast" analysis, a $30 million increase in customer charges, demonstrate that the riders are not risk-neutral from customers' perspective. They claim that the fact that the Utilities have proposed the riders belies any pretense that they are risk-neutral - there would be no point in proposing a rider that would have a "neutral" effect on today's risk allocation. City-CUB Rep. Br. at 26.

8. Commission Conclusions

The Commission has established rates of returns on common equity for utilities by employing financial models designed to quantify the likely cost of attracting capital investment during the time rates are expected to be in effect. In virtually all cases, we have relied on the DCF and CAPM models. In these proceedings, Staff employed the DCF and the CAPM. City-CUB relied primarily on the DCF model and used the CAPM to verify the results. The Utilities used DCF, CAPM and risk premium models, as well as a comparison with ROEs granted to other utilities in and out of Illinois.

As a result, the disputed ROE issues principally concern differences about proper application of the DCF and CAPM models, the inter-relationship of the models, adjustments to results, and the efficacy of the additional models used by the Utilities. While most of these issues involve the mechanics of financial modeling, the Utilities' comparison of the ROEs proposed here with ROEs authorized for other utilities poses broader and more conceptual questions that the Commission will address first.

ROE Comparisons

At several places in their evidence and briefs, the Utilities compare the ROE's recommended here with the ROEs approved in previous cases by this and other commissions. E.g., NS-PGL Ex. PRM-2.0 at 3-6. They assert that previously approved ROEs serve as "guideposts" for our analysis in these cases and insist that they "are not arguing that their returns should be based on the authorized returns of other utilities." NS-PGL BOE at 25. The Commission doubts that the Utilities' return comparisons were offered without the expectation that our decision-making would be affected by them. The Utilities are presumably reluctant to directly press for comparison-based ratemaking because of our previous rejection of that approach. In Commonwealth Edison's most recent rate case, we said:

> 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 factors 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.

Commonwealth Edison, Docket. No. 05-0597, Order, at 153 (June 6, 2006).

That does not mean, though, that the Commission is unaware of the implications of the ROE we adopt for the Utilities. They must compete for investors' money and cannot be deprived of meaningful capacity to do so. Nonetheless, there are important reasons why a commission should not simply match each Utilities ROE to the others previously approved. If our task were merely to maximize the Utilities' ability to attract capital (perhaps to retain investment in Illinois, as the Utilities suggest, Tr. 1047-48 (Moul)), the Commission could just exceed the highest returns already authorized for other utilities. But when the next utility initiated a rate case, we would have to approve an even higher return. Moreover, the Utilities point out that "regulated firms must compete with non-regulated firms in the capital market." NS-PGL Ex. PRM-1.0 at 41. To assure success in that competition, the Commission would presumably have to equal or exceed returns in the unregulated market as well.

Less dramatically, we could aim for an average among existing ROEs. However, some percentage of existing ROEs would have been in effect for multiple years and would have been established under different financial market conditions (*e.g.*, with different rates of inflation and costs of debt). The Commission could narrow its comparison to, say, ROEs approved within the last two years, and peg the Utilities at the average of those. Even then, we would have to ignore any differences among utilities in financial strength, capital structure, credit status and utility-specific circumstances, as well as changes in the financial market during the two-year period. Moreover, while this one-dimensional comparative approach might satisfy us for ratemaking purposes, it would not necessarily attract capital from sophisticated investors, who would evaluate the actual financial strengths and weaknesses of the utilities. Indeed, an ROE simplistically pegged to average recent ROEs might be too low.

Furthermore, by determining the Utilities' ROEs via comparison to existing ROEs, the Commission would be disregarding its duty to impose only cost-based and reasonable rates on the Utilities' customers. Thus, if we succeeded in providing capital attraction to Illinois utilities, we would also be extracting it from Illinois businesses and homeowners, in the form of excessive rates. And, in the future, other Commissioners could reverse the inequity, by intentionally pegging the Utilities' returns to the lowest comparable existing ROEs.

Plainly, although the notion that the Utilities should enjoy at least an average ROE is superficially seductive, it is an unworkable and improper basis for determining utility returns. It would require us to abandon the course we, along with other commissions, have charted for decades. Return determinations are appropriately based on a two-pronged analysis of utility-specific financial characteristics and financial market dynamics and conditions. We have relied upon the financial models and reasonable adjustments to accomplish this. Although even these quantitative mechanisms involve some degree of subjectivity[18] and can, for that reason, be manipulated, they were constructed with the intention of objectively estimating the cost of equity, not to match another utility's ROE.

In sum, the Commission will not award the Utilities the same ROE as, for example, Nicor, solely because they must compete for investment capital. If market dynamics have altered since the Nicor decision in 2005, that will be reflected in the Utilities' ROE. So, too, will utility-specific differences. A critical difference is that the Utilities will enjoy the revenue stability and reduced risk derived from Rider VBA, approved in this Order. Nicor Gas has no such rider.

Another critical difference is the Utilities' recent merger, with WPS, which the Utilities assured us would enhance their financial strength. As the Utilities see it, they have proven that the merged entity, Integrys, "will provide the Utilities with a larger and stronger financial platform," and "has a strong record of maintaining the financial strength of its regulated subsidiaries." NS-PGL BOE at 23-24. The Utilities cannot have it both ways, heralding the increased financial strength derived from their 2007 merger, then requesting an even higher allowed ROE than Nicor received in 2005, based upon the rationale of parity (or more) for its own sake. Accordingly, the Utilities' approved ROE in these proceedings will be determined by application of the financial models and adjustments we have continually relied upon since the early 1980's[19].

The DCF Model

Staff's DCF analysis yields (after adjustment) a cost of common equity of 8.23%. The Utilities believe this is far too low (their estimate is 9.72%). They complain that Staff erred by taking a snapshot of certain DCF inputs (stock prices and dividend data) from a single day in April 2007. The Utilities say the data is now too old. The Commission finds it inevitable that data in pre-filed rate case testimony will reflect some degree of hindsight, at least as a starting point in the analysis. That attribute is common to much of what the parties presented as evidence, including the Utilities' own DCF analysis. Furthermore, we are establishing an ROE that will remain in place until the Utilities' next rate case, potentially long after this Order is entered. As the Utilities state,

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[18] "The truth is that the application of all of the models involves the analyst's judgment in choosing the various inputs to the models from a plethora of financial data." PGL-NS RBOE at 37. "[N]o estimation methodology is entirely objective." City-CUB Init. Br. at 36.

[19] *E.g.*, Central Illinois Public Service, Docket No. 82-0039; Commonwealth Edison, Docket No. 82-0026; Commonwealth Edison, Docket Nos. 83-0537 & 84-0555; Illinois Power, Docket No. 84-0480.

an ROE is intended to provide an opportunity to earn a fair return over “good years and bad.” NS-PGL BOE at 27-28.

Staff is also concerned about the use of historical data in calculating forward-looking ROEs, since all historical data is outdated and may reflect conditions that will not continue in the future. Yet the problems cited by Staff are compounded by short-term “vagaries of the market” (NS-PGL Ex. PRM 2.0 at 7) that can affect stock prices and yields on any given trading day, which Staff proposes as a starting point on its DCF analysis. The use of price and yield averages, as the utilities propose, will tend to smooth out any exogenous short term price and yield inefficiencies that can occur on a single trading day. Thus, Staff’s single data point for use in its DCF is unsatisfactory for the intended purpose in these dockets.

The Utilities further charge that Staff’s DCF results are too low to be credible, suggesting faulty methodology. Staff replies that the Utilities over-emphasize the lowest-ranking results in Staff’s treatment of the nine companies in the utility sample, thereby contradicting the very purpose of assembling a multi-utility sample in order to derive an average. There will always be a high and a low in a sample, Staff says, but the meaningful data point is the average. While Staff is correct on these points, there is another obvious check on Staff’s results: the use of an alternative sample date or an average across a six-month, or other, period that the utilities argue would be better. We believe that the anomalous results produced by Staff’s DCF analysis render it flawed and therefore unusable to determine ROE in this case.

We note that the Commission has traditionally relied upon a single day’s data in applying the DCF analysis, and we are very reluctant to deviate from Commission ratemaking practice. However, the whole point of conducting such analyses is to develop a proxy for the appropriate ROE. When it can be shown that the proxy itself strays from a zone of reasonableness to the degree where it offers an unreliable estimate of the appropriate ROE, as the Utilities have demonstrated with Staff’s DCF analysis in this case, deviation from accepted practice may be warranted. We encourage parties to continue to provide reliable DCF analyses for the Commission’s ROE deliberations.

Staff and the Utilities used a quarterly version of the model and disagree with the choice of City-CUB to use an annual version. The Commission finds that the quarterly version of the DCF model is superior. We remain convinced, as we have been in numerous previous rate cases, that the quarterly version of the model should be used to correctly reflect the time-sensitive value of the dividends reflected in the DCF model. City-Cub’s arguments, which the Commission has considered in previous cases, have not altered our view. Since the City-Cub model does not use quarterly dividend data, it will not be considered in evaluating the utilities’ ROE.

The CAPM Model

We do not find City-CUB's arguments against the CAPM sufficiently persuasive to abandon the CAPM. In many prior proceedings, the Commission has regarded the CAPM as a useful tool based upon sound financial theory. As the Utilities and Staff indicate, investors are only rewarded for accepting systematic risk. That is, any risk that an investor can eliminate by holding a fully diversified portfolio of securities need not be reflected in the investor's required return. While City-Cub did not explicitly rely on their CAPM results in developing their recommended return on common equity, they did claim it supported their DCF results.

The Commission rejects City-Cub's suggestion that unadjusted, or raw, betas should be used as inputs to the CAPM. As both the Utilities and Staff point out, the financial literature and empirical studies support the use of adjusted betas as better forward-looking measures of systematic risk. We have regularly relied upon adjusted betas in establishing authorized returns on common equity and the arguments of City-CUB have not convinced us to change this practice.

City-Cub also object to the manner in which the Utilities and Staff developed their expected market risk premium for use in the CAPM. As with the risk premium between utility cost of debt and cost of common equity, the expected market risk premium relative to the risk free rate is not stable over time. As a result, the Commission concludes it is preferable to rely upon a current estimate of the expected market risk premium rather than upon an approach derived from academic research.

Risk Premium Model

The Commission understands that the CAPM is similar to a risk premium model. However, the risk premium model that the Utilities used in addition to their CAPM is unhelpful. The primary reason that the Commission has repeatedly rejected that type of risk premium analysis is the difficulty in establishing the "correct" risk premium. The risk premium for common equity relative to debt changes over time and, in the Commission's view, there is no objective mechanism for establishing that risk premium. While all cost of equity analyses require the application of judgment, this particular approach is primarily a matter of judgment and we are unwilling to rely on such a subjective analysis.

The Utilities acknowledge that this Commission "has in the past rejected the RP model as a valid basis on which to set [ROE]." NS-PGL BOE at 29 (citing CILCO, Docket No. 02-0837, Order (Oct. 17, 2003)). Despite that, the Utilities contend that the risk premium should still be utilized, in conjunction with the Utilities' other models, to determine ROE in the instant dockets. The Utilities assert that the Commission ratified that viewpoint in Commonwealth Edison, Docket No. 05-0597, Order (June 26, 2006), when we relied, in part, on an intervenor witness whose ROE recommendation was derived from three models, including the risk premium. Staff responds that the witness did not give risk premium equal weight with his other models, that the Commission also used Staff's recommendations (without risk premium) to set ROE, and that the issue was not analyzed as it has been here. Staff RBOE at 23-24. The Commission again rejects the risk premium model. Insofar as it crept into decision-making in Docket No. 05-0597, that was an anomaly we will not repeat.

Staff's Adjustments

Staff made downward adjustments to the cost of common equity results to reflect its view that Peoples Gas and North Shore each have less financial risk than the proxy utility sample. Staff accomplished this by comparing the benchmark financial ratios (*e.g.*, funds from operations/interest coverage) of the Utilities and the sample companies. Staff concluded that the resulting financial characteristics of the Utilities' are consistent with a higher credit rating than the utility sample's collective credit rating. The Utilities urge the Commission to reconsider its past practice of accepting such adjustments. The Utilities argue, in essence, that their own proxy utility sample is similar in total risk (operational and financial) to both Peoples Gas and North Shore. They assert that because their sample was selected on the basis of total risk, not just operational risk, a financial risk adjustment is unnecessary and inappropriate. Staff says it accepted that the utility sample had operational risk that was similar to the Utilities', but did not evaluate the similarity of financial risk until after the cost of equity analysis was performed on the sample.

The Utilities did endeavor to consider financial risk in their presentation, including comparing credit ratings. However, the Utilities' credit ratings have been impacted by non-regulated activities. Section 9-230 of the Act requires the Commission to ensure that such activities are not reflected in the authorized rate of return. While the Utilities agreed that an adjustment to the embedded cost of debt was necessary to remove the impact of non-regulated activities, their recommended return on common equity does not appear to reflect such an adjustment.

The Utilities contend that some of the companies in the utility sample are, like the Utilities, also affected by the increased operating risk of their parent companies. They further allege that Staff's witness apparently knew this, because she adjusted the S&P business profile scores of those utilities. But, according to the Utilities, she did not adjust their credit ratings, thereby exaggerating the differential in creditworthiness between the sample companies and the Utilities. NS-PGL BOE at 34. Staff explains, however, that the sample companies' credit ratings did not require adjustment because they already reflected the credit ratings of their parent companies.

On exceptions, the Utilities also argue that even if the Utilities' financial risk is lower than the average of the utility sample, Staff "failed to confirm that there are no risk differences that offset that 'financial risk' difference." NS-PGL BOE at 35. The Utilities assert that there are several pertinent financial risk factors, that the Utilities and the sample companies are, respectively, higher on some and lower on others, and that they "balance out" overall. Staff's shortcoming, according to the Utilities, is the failure to prove that the other factors do not cancel out the impact of the Utilities' ostensibly higher credit rating.

The Commission categorically rejects the Utilities' argument, which turns the burden of proof in these proceedings on its head. Staff is not obliged to disprove all potential counter-arguments to its recommended adjustments. The burden is on the Utilities to prove the reasonableness of their proposed rates, including the reasonableness of the elements, such as ROE, that make up those rates. In this specific instance, Staff presented sufficient support for its financial risk adjustment to require the Utilities to rebut that support. Staff did not need to disprove any Utilities' rebuttal *that was not made*.

The issue, then, is whether the Utilities offered sufficient evidence and argument to rebut the basis for Staff's adjustments. Their evidence is Mr. Moul's opinion that "on balance" the performance of the nine companies in the utility sample "average out" with the Utilities, with regard to the multiple financial risk factors Mr. Moul applied. No calculations support that opinion. The risk factors are not weighted and compared quantitatively to prove equivalency between the Utilities and the utility sample. Nor is the quantitative impact of those risk factors compared to the quantitative impact of the Utilities' linkage to its parent company's credit standing. Mr. Moul forthrightly acknowledged that quantifying the impact of separate financial fundamentals is generally not possible. Tr. at 1071-72. Therefore, Staff did not need to disprove that the risk factors "balanced out" or that they did not offset Staff's adjustments.

By performing its financial ratio analysis on the regulated entities here, Staff has been able to isolate their financial risk. Staff's analysis thus demonstrates that the Utilities are less financially risky than the utility sample and that downward adjustments to the cost of equity results for that utility sample are necessary. Staff's adjustment is theoretically sound and consistent with similar adjustments accepted by the Commission in previous rate cases.

<u>The Utilities' Adjustments</u>

Staff states that the difference between the Utilities' CAPM and DCF analyses and its own is only 11 basis points, once Mr. Moul's adjustments are removed. Thus, Mr. Moul's financial leverage adjustments require discussion. The Utilities adjust both their DCF and CAPM analyses so that the authorized return applied to the Utilities' book value capital structures will, in their view, correctly represent investor-required return. They maintain that the costs of equity produced by the financial models are based on the market value capitalizations of the utility sample. They further assert that the proxy group's market value capitalizations contain more equity and less financial risk (debt) than its book value capitalizations used for ratemaking purposes, which contain less equity and more financial risk. The Utilities argue that when a market-based cost of equity is applied to a book value capital structure there is a mismatch in financial risks and under-recovery of allowed the utility's allowed return.

In the Commission's judgment, the book value capital structure reflects the amount of capital a utility actually utilizes to finance the acquisition of assets, including those assets used to provide utility service. In establishing the overall or weighted average cost of capital, the proportion of common equity, based on the book value capital structure, is multiplied by market-required return on common equity. The

Commission has used this approach in establishing utility rates for at least twenty-five years. E.g., Ameren Order, Docket Nos. 06-0070/06-0071/06-0072 (consol.) at 141 ("[t]he Commission observes that it has repeatedly rejected arguments in favor of using market-to-book ratios as the basis for establishing cost of common equity"). Market value is not utilized in this calculation because it typically includes appreciated value (as reflected in its stock price) above the Utilities' actual capital investments.

The Utilities assert, however, that theirs is a "financial leverage adjustment," not a "market-to-book adjustment." NS-PGL BOE at 30-31. This elevates form and nomenclature over substance. The Utilities perform their adjustment by first determining the cost of equity for a utility (represented by the average of the utility sample) with a 100% equity capital structure, using the market value of the equity (the result is 8.35%). From that, they then calculate the ROE for a utility (again represented by the average of the utility sample) based on the equity reflected in a book value capital structure (a 9.53% result)[20]. NS-PGL Ex. PRM 1.13, p. 13-14. The Utilities recognize that this process is equivalent to applying an unadjusted equity return to the market value of the utility's shares, resulting in an adjustment identical to the one we rejected in the Ameren Order. City-CUB Cross-Ex. 5. Again, our practice is to approve a return on a utility's actual investments at book value, not on the appreciated value of its common stock, however calculated and denominated.

Further, the Utilities have failed to establish why a mismatch between the financial risk reflected in the book value and market value capital structures is problematic. If the Utilities were correct that regulatory commissions, including this one, have been understating the market-required return on equity for twenty-five years, then the market values of common equity for utilities would not have remained well above the book values during that time. A practice of routinely understating the market-required return on common equity would have surely driven down the market values of common equity to near book value, but that has not happened[21]. Accordingly, the Commission does not agree that an adjustment to the market required return on common equity is necessary to reflect the difference in financial risk between book value and market value capital structures. Therefore, we reject the Utilities' financial leverage adjustment to their DCF results and their proposal to impose a similar leveraging adjustment to the betas used in their CAPM analysis.

Inter-Relationship Among the Models

City-CUB points out the disparity between both the Utilities' and Staff's DCF and CAPM analyses. There is a 232-basis point divergence between the Utilities' adjusted

[20] Stock flotation costs are not included in these calculations.
[21] The Utilities call this conclusion "speculative." NS-PGL BOE at 33. We disagree. It is the accumulated experience of this Commission, and is embedded in the discretion with which we determine ROEs. In these proceedings, it is supported by evidence of the Utilities' own stock appreciation above book value and their earnings, in most years, above their allowed returns.

results[22] and a 311-basis point differential between Staff's. City-CUB questions whether such dramatically disparate results can both be correct (the difference between City-CUB's models is only 7 basis points).

Another seeming anomaly is not in City-CUB's favor. Staff's, the Utilities' and City-CUB's DCF models are less than 100 basis points of each other (8.23%, 8.11% and 9.01% (unadjusted), respectively). But while Staff's CAPM (11.34%) and the Utilities' (10.79% unadjusted, 11.85% adjusted) are relatively close, City-CUB's CAPM result is 8.18%. Viewed in this way, City-CUB's CAPM is the outlier.

The point is not that City-CUB's CAPM modeling is incorrect, but that the proponents of the same model will obtain different outcomes when they make different assumptions about inputs or different adjustment to their results. Similarly, the various models will yield different costs of common equity because they are rooted in different theories of how to estimate those costs. While the Commission might be tempted to disregard the CAPM here, we know, from experience over time, that the CAPM will show less volatility than the DCF model. Our continuing policy is to employ both models and to calculate a mid-point that accords due regard for their different underlying theories.

Effect of the Proposed Riders

In this Order, below, the Commission approves Rider VBA as a 4-year pilot program. That Rider affords the Utilities revenue stabilization when customer usage varies. Staff and City-CUB argue that a downward adjustment to the cost of common equity should be made, because Rider VBA (like the other riders, which are not approved here) would reduce the Utilities' risk. That reduced risk, Staff and City-CUB say, should be reflected in the authorized return on common equity. The Utilities disagree, asserting that some of the utilities in the proxy sample have similar types of riders or comparable revenue stabilization mechanisms. Furthermore, the Utilities argue, the variations addressed by Rider VBA, in particular, are not relevant to investment decisions and are not measured under the CAPM model. Also, the Utilities argue, Rider VBA is "risk neutral" because customers benefit when weather increases gas consumption. NS-PGL Init. Br. at 90.

Initially, the Commission concludes that the Utilities' list of revenue stabilization mechanisms for many of the companies in the utility sample, NS-PGL Ex. 2.4, is insufficient for our purposes here. The Utilities did not compare the operation or quantitative impact of Rider VBA with the proxy companies' listed mechanisms or explain how those mechanisms have (or have not) been reflected in the proxy

[22] The Utilities stress that their *unadjusted* results are "only" 178 basis points apart. PGL-NS RBOE at 37. However, they have insisted throughout these proceedings that their results must be adjusted to be valid, and that other parties' results are invalid without those adjustments.

companies' approved cost of capital[23]. Thus, the record contains no quantitative evidence for comparison and no comparative analysis of the operational characteristics of the various mechanisms and Rider VBA. Given that the cost of equity is measured in (and disputed over) hundredths of a percentage point (i.e., in basis points), this imprecision is significant.

The Utilities' assertion that investors do not take into account the relationship between weather and a gas utility's expected earnings is belied by the Utilities' own testimony. "[T]he market prices of these [Utility Sample] companies' common equity reflect the expectations of investors related to a regulatory mechanism that adjust [sic] revenues for abnormal weather." NS-PGL Ex. PRM-1.0 at 5.

As for the Utilities' claim of "risk neutrality" with Rider VBA, the Commission finds this irrelevant. Rider VBA stabilizes *the Utilities*' revenues. We are not establishing an ROE for ratepayers. Moreover, all the Utilities are really saying is that consumers are not *worse off*, in a limited sense, when weather plummets and usage rises.

Staff contends that Rider VBA (and the other riders) would reduce the Utilities' operational risk, which is part of investment risk. Thus, Staff states, it would assess the reduced risk associated with the relevant rider, evaluate the Utilities' operating ratios based on the reduced risk, and reduce ROE to account for the difference in total risk, as compared to the utility sample. Staff Ex. 6.0 at 22-23. Staff suggests that the Utilities' riders might well reduce operating risk to a point where their S&P business profile were improved. Such improvement "would result in financial ratios that are consistent with stronger credit ratings than Staff's cost of equity recommendations reflect." Id. at 26. The Utilities' own view is consistent with the foregoing analysis:

> Therefore, the [Utilities] can be expected to realize a short-term benefit of improved liquidity as a result of implementation of these Riders. Indeed, the Riders will remove some of the [Utilities'] cash flow variability, which would be viewed favorably by the credit rating agencies. As such, the Riders would help the [Utilities] to sustain [their] credit ratings. These are beneficial impacts which will be most directly manifested at the credit quality level rather than the determination of the [Utilities'] cost of equity.

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[23] Presumably, the Utilities expected the Commission to perform the detailed comparisons. We attempted that task, through our ALJs, and we note, for example, that Piedmont Natural Gas Company's "Rate Stabilization Mechanism" commits the utility to specified ROE limits. Piedmont's rates are adjusted only twice annually, as true-ups. South Jersey Industries' "Temperature Adjustment Clause," which terminated in 2006, had only annual true-ups, not monthly adjustments like Rider VBA. New Jersey Resources' "Weather Adjustment Clause" appears to merely revise HDDs annually. We have identified these provisions, which emphasize apparent differences from Rider VBA, to illustrate the limited usefulness of the Utilities' presentation. If the Utilities' wanted certain inferences drawn from its list, it was up to them to make the detailed comparisons that would have supported those inferences. As the record stands, the list, by itself, does not persuade us that the companies in the utility sample have mechanisms that stabilize revenue and reduce risk in a manner comparable to Rider VBA.

NS-PGL Ex. PRM-1.0 at 7. (Insofar as the Utilities' divorce credit quality from the ROE determination, the Commission simply disagrees. That is why we approved Staff's cost of equity adjustments, which reflect the affect of credit standing and financial ratios.)

City-CUB, as discussed above, attempt to estimate the impact of the riders on cost of equity by reference to the insurance policy the Utilities' parent corporation formerly purchased to hedge against mild weather. In City-CUB's view, the policy proceeds represent an extremely conservative quantification of the impact of the riders on ROE (treating the amount of the policy payout as a proxy for additional revenue). The Utilities assert that City-CUB's methodology is incomplete because it omits necessary elements.

The Commission finds that Rider VBA will lessen the Utilities' risk associated with their cash flow. Moreover, we agree with Staff's recommendation that there should be a downward adjustment to the cost of common equity to account for the reduced risk associated with the accepted riders. Staff Ex. 10.0 at 23. Staff provides guiding principles for quantifying that diminished risk but does not quantify it. City-CUB recommend a sixty (60) basis point reduction if both Rider VBA and UBA are accepted, however we find compelling the Utilities' criticism to the City-CUB analytic approach of using the insurance model. NS-PGL Init. Br. at 89-90. While the record in this case lacks an exact calculation of the reduction in risk due to Rider VBA, we note that determining the cost of common equity is not an exact science. Amax Zinc Co. v. Illinois Commerce Comm., 124 Ill. App. 3d 4, 11-12 (5th Dist 1984). Overall, we find the record to support a downward adjustment, and in the absence of an exact calculation we find it reasonable to reduce the return on common equity by ten (10) basis points for the duration of the pilot program.

As noted later in this Order, the Commission accepts Rider VBA as a 4-year pilot program. To aid us in monitoring this pilot and its impact on the Utilities' rates of return, we direct Staff to provide the Commission with an annual report on Rider VBA's effect on those returns. If Rider VBA is to become permanent, we expect the parties to quantify thoroughly the effect of Rider VBA on ROE in future cases.

Approved ROE

Based on the foregoing discussion, the calculation of ROE will be affected by the following conclusions: (1) the DCF analyses performed by Staff and City-Cub will not be used in the calculation; (2) the Utilities' risk premium model will not be used in the calculation; (3) the Utilities' financial leverage adjustment is rejected; (4) Staff's recommended adjustment to remove the effect of the Utilities' affiliation with unregulated entities is accepted; (5) Rider VBA reduces the Utilities' risk, which warrants a reduction in ROE by ten (10) basis points; and (6) evidence regarding the allowed ROEs in other cases cannot inform as to the appropriate ROE in the present case.

Based upon its review of the record, and consistent with the conclusions above, the Commission finds that an average of the Utilities' unadjusted DCF model, the Utilities' CAPM model, and Staff's CAPM analysis forms an appropriate basis to determine ROE. Exhibit 1 to the Utilities' Brief on Exceptions makes this calculation, which results in 10.38%. This will form the basis of the ROE calculation.

Taking into account Staff's recommended adjustment to remove the effect of the Utilities' affiliation with unregulated entities, the resulting ROEs for Peoples Gas and North Shore are 10.29% and 10.09%, respectively. Additionally, the Commission deems it appropriate to reduce the Companies' ROEs by ten (10) basis points to reflect the reduction in risk associated with the Rider VBA pilot program. Therefore the Commission finds reasonable and supported by the record the resulting value for ROEs of 10.19% for Peoples Gas and 9.99% for North Shore.

Taking into consideration the Commission's conclusions regarding capital structure, cost of long-term debt, and cost of common equity the Commission finds that Peoples Gas should be authorized to earn a rate of return of 7.76% on its rate base and that North Shore should be authorized to earn a rate of return of 7.96% on its rate base. The tables below show the calculation of those authorized rates of return:

Peoples Gas

Component	Percentage	Cost	Weighted Cost
Long-term debt	44.00%	4.67%	2.05%
Common equity	56.00%	10.19%	5.71%
Total	100.00%		7.76%

North Shore

Component	Percentage	Cost	Weighted Cost
Long-term debt	44.00%	5.39%	2.37%
Common equity	56.00%	9.99%	5.59%
Total	100.00%		7.96%

9. North Shore

Most of the foregoing analysis for PGL applies equally to North Shore. Insofar as North Shore warrants different consideration and/or a different outcome, that has been provided above.

D. Flotation Costs

In his market model analyses, Utilites witness Moul included a standard adjustment for the flotation costs (the underwriting discount and stock issuance expenses) associated with issuing new common stock, namely. Mr. Moul based his nineteen (19) basis-point adjustment on the 3.9% average flotation costs incurred by the utilities in the utility sample during the period 2001-2005. Also, the Utilities state they have previously incurred, but did not recover, flotation costs totaling $485,000 for each company. They argue that if Mr. Moul's flotation cost adjustment is rejected, then the Commission should at least authorize an adjustment that allows recovery of previous flotation costs. NS-PGL Init. Br. at 93.

Staff says flotation costs are recoverable only if a utility can verify both that it has incurred the specific amount of flotation costs it seeks and that those costs have not been previously recovered. Staff charges that instead of using the Utilities' actual flotation costs, Mr. Moul applied a generalized flotation cost estimate based on public offerings of common stocks by gas utilities from 2001 to 2005. Staff underscores that the Commission has repeatedly rejected generalized flotation cost adjustments in previous cases. Staff adds that we rejected North Shores and Peoples Gas' flotation cost adjustments in Docket Nos. 91-0010 and 91-0586. Staff Init. Br. at 75-76.

Staff says that the Utilities' supporting evidence (NS Ex. BAJ-1.3 and PGL Ex. BAJ 1.3 - i.e. Schedule D-5) does not show that a single dollar of the proceeds from the Peoples Gas Energy common stock issuances presented in those exhibits was ever invested in the Utilities, let alone whether any was used for Utility purposes. Staff argues that the burden of proof rests on the utility to prove the reasonableness of the components of the revenue requirement. Staff Rep. Br. at 31-34 (citing Citizens Utility Board v. Illinois Commerce Commission, 276 Ill. App. 3d, 730, 746 (1995)). Furthermore, Staff maintains, even accepting as true that the Utilities incurred flotation costs in the amounts set forth in Schedule D-5, the Utilities merely imply that they have not previously recovered those flotation costs through rates, by referencing several past Commission Orders. However the Commission has stated that the absence of a reference to recovery of such costs in previous orders is not sufficient evidence to support a present adjustment. Docket No. 91-0193, Order at 106 (March 18, 1992,).

According to the City-CUB, Mr. Moul's proposed adjustment for flotation costs violates Commission policy of allowing flotation costs only under very limited circumstances. City-CUB state that Mr. Moul addresses only a generalized adjustment that is not based on specific costs incurred or anticipated by either of the Utilities. City-

CUB Init. Br. at 49-50. City-CUB also emphasize that the Utilities elected to use a test year in which no equity was issued.

City-CUB agrees with Staff that the Utilities have not proven that the equity issuance costs identified in their exhibits are unrecovered. According to the City-CUB, the costs were purportedly incurred fifteen or more years ago. Also, the Utilities, as wholly-owned subsidiaries with no public shares, do not incur such costs directly and the allocation holding company costs among regulated and unregulated affiliates is not addressed by any evidence. Id. at 49; Rep. Br. at 32-33.

Commission Conclusions

The Utilities seek a standard flotation cost adjustment of nineteen (19) basis points, and also request recovery, for each company, of $485,000 of flotation costs purportedly incurred but not previously recovered. The Commission will not accept a "standard" flotation cost adjustment, which fails to reflect the specific circumstances of each individual Illinois utility involved. Further, there is no flotation in the test year, and no specific flotation planned, nor do the Utilities address how the cost of stock issuance by their parent corporation is allocated to their regulated activities.

As for the Companies' allegedly unrecovered prior flotation costs, the record does not support recovery now. In order to qualify for a utility specific flotation cost adjustment, the utility must do more than (for the first time in its brief) identify numbers in its initial filing. Even if this request would not violate the prohibition on retroactive ratemaking, there is no adequate evidence connecting old stock issuances to these Utilities or negating prior recovery.

E. Weighted Average Cost of Capital

1. Peoples Gas

As we stated in connection with Peoples Gas' return on common equity, Peoples Gas' approved weighted average cost of capital is 7.48 %, including 4.67% long term cost of debt and 9.7% return on common equity.

2. North Shore

As we stated in connection with North Shore's return on common equity, North Shore's approved weighted average cost of capital is 7.69%, including 5.39% long term cost of debt and 9.5% return on common equity.

V. HUB SERVICES (All issues relating to Hub services)

A. Manlove Field

The Hub is a group of interstate gas transmission and storage services available to wholesale customers. Hub services are made available by Peoples Gas using portions of the capacity at Peoples Gas' underground storage facility, Manlove Field, and Mahomet Pipeline. The Federal Energy Regulatory Commission approves the maximum rates that Peoples Gas can charge customers that use these Hub services , and the resulting revenues are credited to retail customers through the purchased gas adjustment clause (Rider 2).

Staff takes the position that there is a substantial risk that the cost of the additional base gas that Peoples Gas is likely to have to add to Manlove Field to support provision of Hub services is greater that the Hub revenues, and thus, is imprudent to operate. As such, Staff would recommend that the Hub be discontinued. City-CUB and the AG do not weigh in on all aspects of the dispute. But, they share a concern and each makes specific recommendations going forward.

The Commission here considers all of the evidence of record and positions taken in the matter.

1. Peoples Gas

Manlove Field, Peoples Gas explains, is an underground aquifer, i.e., porous rock that bears water in the pores. PGL Ex. TLP-1.0 at 3. Its witness observes that Manlove Field is particularly complex, even as aquifer storage fields go. Id. at 4. On the whole, Manlove is large, inefficient (a relatively high percentage of gas becomes trapped), and both difficult to manage and characterize. Id. at 3; Tr. at 472 & 492. All these features and the fact that the field has been used for gas storage operations for years, renders it difficult to ascertain which areas of the aquifer are virgin aquifer and what areas have trapped gas. It is also difficult to determine whether new injections will invade virgin aquifer or previously invaded areas. NS-PGL Ex. TLP-3.0 at 10.

When Peoples Gas introduced Hub services, it did not install additional wells or other facilities to enable it to provide the service. It merely expanded the amount of working gas at Manlove Field by injecting more gas into the storage field and increased working gas by 10.2 Bcf. Staff Ex. 10.0 at 6.

In all, from 1997 through 2006, Peoples Gas states, it capitalized an additional 7.88 MMDth of its Manlove injections as cushion gas. Id. at 11. Based on the various metrics used by Peoples Gas to assess the storage field's performance, this is keeping Manlove Field operating, and as expected. NS-PGL Ex. TLP-2.0 at 7-9.

Peoples Gas explains that it did not inject additional cushion gas at the time it started offering Hub services. What Peoples Gas has done instead is to characterize a percentage of the gas it injects each day during the injection season as cushion gas. PGL Ex. TLP-1.0 at 10. Some of that annual cushion gas allotment is supporting Hub operations, and the rest is supporting general storage operations in Manlove Field. NS-PGL Ex. TLP-3.0 at 6-7. Peoples Gas estimates the amount of cushion gas that would be attributed to the Hub storage to be approximately 1.34 MMDth. NS-PGL Ex. TLP-2.8.

2. Staff's Position

Staff takes the position that Peoples Gas should have, but did not inject more base gas at Manlove Field to support the start of Hub operations. The testimony of Staff's witness Rearden, who relied upon Staff witness Anderson's technical expertise for the technical definitions in his testimony, defines the essential terms for the issue.

He explains that “top gas” (also known as “working gas”), is what is anticipated to be used or cycled in normal operation during the injection or withdrawal season. Staff Ex. 12.0. “Recoverable base,” according to Mr. Rearden, is the natural gas that is not normally cycled but which provides pressure in the reservoir to cycle the top gas. Id. And, he further defines non-recoverable base gas as what is trapped in the reservoir and cannot be recovered but what is necessary to support the top gas. Id. Both of the latter constitute and are interchangeably referred to in testimony as “base”, “maintenance,” or “cushion” gas.

Staff points out that Peoples Gas increased Manlove Field’s working gas inventory by 10.2 BcF in order to be able to provide Hub services. To increase the Manlove Field working gas, Staff witness Anderson testifies, Peoples Gas needs to inject gas into the field that cannot be withdrawn. Staff Ex. 10.0. He estimates that base gas needed to increase working inventory is approximately four times the amount of the increase in Manlove Field’s working gas. This base gas becomes part of rate base and since base gas cannot be withdrawn, Staff notes that it is treated as a capital investment by Peoples Gas. Staff Ex. 12.0 Revised at 10-11.

Prior to initiating Hub services, Staff reasons that Peoples Gas had to decide whether to either inject the necessary base gas immediately into Manlove or to continually inject base gas. Staff observes that Peoples Gas has chosen to continually inject base gas. While Staff does not disagree that Peoples Gas can operate Manlove in this manner, its decision causes some concern.

Staff maintains that forty years of operating history at Manlove as well as the operation and theory behind all aquifer storage fields, dictate that all working inventory requires base gas. Staff Ex. 22.0 at 24. And, it argues, Peoples Gas failed to demonstrate that its expansion of Manlove’s working inventory for Hub operations did not also require an expansion in the volume of base gas.

Staff believes that Peoples Gas’ choice to delay the initial injection of the base gas necessary to support Hub operations spreads the cost of that additional base gas out over time, but also creates a situation where the ultimate cost associated with that base gas will increase.

On the basis of its gas cost estimates and calculations, Staff argues, Peoples Gas’ decision to not inject base gas when Manlove was first expanded to support Hub services will expose it to a significant cost in the future. Staff maintains that the cost exposure for the future injections of base gas necessary to support the Hub operations should be borne by Hub services and not Peoples Gas’ ratepayers. Staff Ex. 22.0 at 32.

Staff takes note of the claim by Peoples Gas that less base gas is needed now than in the past because Manlove Field trapped or retained more initial gas injections than subsequent injections, thus relatively less gas was trapped in more recent injections. NS-PGL Init. Br., at. 95-96. Staff notes too, that PG provided a graph (North Shore/Peoples Ex. TLP-2.6) that shows a 7-year running average of the additional cushion or base gas added to the field since the field began operation. Staff points out that this graph covers two distinct injection paradigms. From 1964 to 1998, Staff notes, cushion gas was injected only when Manlove Field's performance declined. From 1999 to 2006, however, cushion gas was injected on a continuous basis and recorded as a percentage of volume of the whole-gas injections. As such, Staff observes that Peoples Gas employed different cushion gas injection methodologies in these respective times. But, Staff claims that there is nothing in this information to demonstrate that the maintenance gas needs at Manlove Field will not increase in the future. (Staff Ex. 22.0 at 29-30). And, Staff submits that Peoples Gas' claim that base gas requirements reduce over time, is disputed by its recent need to increase the base gas continuous injection volumes from 2% to 3.5%.

Staff notes that Peoples Gas asserts that its recent decision to increase the percentage of gas injections from 2% to 3.5% does not represent an increase, because there was a metering problem at Manlove caused by pulsations of the compressors. NS-PGL Init. Br. at 97; NS-PGL Ex. TLP-2.5. Peoples Gas believes that it was likely that it was injecting over 3% instead of the 2% injections it thought it was making at the time. In Staff's view, this is mere speculation and should be treated as such.

Staff rejects the notion that the working inventory in Manlove Field can be increased by 10.2 Bcf to provide Hub services without any additional injections of base gas. Staff solidly maintains that all working inventory in Manlove Field, whether for the ratepayer or the Hub, requires base gas to operate. Staff Ex. 10.0, at 17-18. As such, Staff has concerns going forward. Given the lack of studies on the exact volume of base gas required to support Hub operations, Staff created its own analysis and estimated that 45.3 Bcf of base gas was needed to support Hub operations. Recognizing that its methodology provides only a rough estimate in the situation, Staff nevertheless maintains that it shows the obvious disparity between Peoples Gas' claim of zero and the magnitude of the ultimate base gas volumes it believes are needed to support Hub operations. Staff Ex. 10.0 at 21-22.

According to Staff, Peoples Gas never conducted any studies to determine the amount of base gas its Hub operations specifically require. It points out that Peoples Gas' reservoir studies only review the amount of maintenance gas that is continually needed to support the total inventory of Manlove Field. For example, Staff observes that Peoples Gas' study shows Manlove Field now needs 3.5% of injected volumes to support its' performance. NS-PGL Ex. TLP-2.1. Staff believes that this underestimates the need for additional base gas.

In Staff's view, Peoples Gas' own evidence indicates an obvious need for base gas. Staff cites Peoples Gas' witness Puracchio's statement that, "Gas in the Manlove Field reservoir is under pressure and tends to expand, radially invading new areas. As this occurs, some of the gas inevitably becomes trapped as cushion gas." PGL Ex. TPL-1.0 at 10. Staff does not dispute this statement, and observes that this testimony was provided to support the continuous need for maintenance or base gas injections into Manlove in order to maintain field performance over time, not in relation to Hub expansion. Staff's position, however, is that this statement applies for any additional gas injected into Manlove field and including the Hub expansion. Staff Ex. 22.0 at 12-13. In other words, Staff argues, anytime additional gas is injected into Manlove a significant amount of that gas is lost.

Staff refers to Peoples Gas' Ex. TLP-2.1, which it describes as a report that details the information and methodology used to construct a new computer model of Manlove. The result of this study, Staff observes, showed the need to increase the percentage of injections retained as base gas at Manlove from 2% to 3.5%. While Staff does not dispute the need to increase the percentage of injections retained for base gas injection from 2% to 3.5%, it is still concerned that this study could ultimately understate the percentage of injections of cushion gas needed at Manlove.

3. Peoples Gas Response

Peoples Gas asserts that Staff is mistaken in assuming that Peoples Gas expanded Manlove Field's working gas by 8 Bcf all in the first year. In that first year of 1998, it points out, Hub inventory was just 1.5 Bcf, and did not go above 8 Bcf until 2002.

While the cornerstone of Staff's argument is that the sudden large increase of working gas should have been accompanied by a large injection of cushion gas, Peoples Gas explains that the expansion of Hub services was much more gradual. NS-PGL Ex. TLP-2.8. Therefore, it was quite reasonable, says Peoples Gas, to continuously inject cushion gas to support all operations at Manlove Field, as opposed to inputting a single large injection.

Over the forty years Manlove has been in existence, Peoples Gas observes that it has injected a great deal of gas into the field as base gas. This is because gas slowly creeps outward over time, invading new areas. When Peoples Gas began gradually increasing its working gas to enable Hub operations, it was initially able to do so with the support of base gas already underground. To support all storage operations, including both Hub and other storage, Peoples Gas began to add base gas going forward at the rate of 3.5%. This operation, Peoples Gas asserts, has proved adequate to keep the field operating properly.

If the situation were that it is injecting too little cushion gas, Peoples Gas asserts that it would notice, and in a relatively short time, that Manlove was not performing properly. Tr. at 485. In operating an aquifer storage field, Peoples Gas explains, the operator watches various metrics such as pressure and peak deliverability, to see if the field is operating as expected (Tr. at 485-486) and that is just what Peoples Gas has done. When, after fixing a metering problem, Peoples Gas was inadvertently under-injecting cushion gas by a shortfall of just 0.6 MMDth per year, Peoples Gas noticed a significant drop-off in field performance. Then, when Peoples Gas increased its injections to approximate their previous levels, field performance promptly returned to normal. NS-PGL Ex. TLP-2.0 at 7-8. Peoples Gas points to this scenario as proof that, if Staff were correct that Peoples Gas has been severely under-injecting cushion gas, Peoples Gas would see it in the performance of the field. Since field performance has been quite good in the last several years, Peoples Gas maintains that its capitalized cushion gas injections of 7.88 MMDth have been sufficient.

4. Commission Analysis and Conclusion

With respect to the operations at Manlove Field, and the concerns raised by Staff, the Commission must decide whether Peoples Gas has been making sufficient injections of cushion gas to support its operations. Based on the evidence showing that it has been monitoring field performance, with no fall-off in performance since it has been continuously injecting 3.5% cushion gas, we find that Peoples Gas' cushion gas injections have been reasonable. In total, the capitalized injections since Peoples Gas' last rate case amount to 7.88 MMDth of gas.

Staff is correct that Peoples Gas did not inject new cushion gas to support Hub services at the time it initially began offering those services. At the same time, however, Staff concedes that Peoples Gas could just as well choose to add cushion gas gradually and continuously to support the expanded use of Manlove Field. Staff Init. Br. at 97. In other words, there were two reasonable ways to proceed. The option that Peoples Gas chose was to gradually increase its use of Manlove Field for Hub services, while continuing to inject cushion gas to support the overall operation of the field. According to the record, this appears to be working. There was only a short period during which cushion gas injections were inadvertently decreased and this caused Peoples Gas to notice a drop in field performance. When it increased injections to the correct amounts, however, the field responded quickly and has been operating normally. This performance and the attention to performance is the best evidence. It establishes for the Commission that, in both amount and manner, the cushion gas injections reported by Peoples Gas have been sufficient.

For the purposes of considering Staff's contention that offering Hub services at Manlove was imprudent, the Commission finds that Peoples Gas' calculation of 1.34 MMDth of the total 7.88 MMDth of cushion gas injections is reasonable. NS-PGL Ex. TLP-2.8 provides this calculation, and is the only credible evidence in the record. The Commission finds Staff's calculation that the Hub required 45.3 Bcf of base gas, based on the "historical ratio" of working gas to base gas, to be not reasonable under the entirety of the facts and circumstances borne out by the record.

B. Hub Services

1. Peoples Gas

Peoples Gas explains that Hub services are comprised of two types of FERC-jurisdictional services. First, the Hub includes the transportation and storage provided by Peoples Gas pursuant to a FERC Operating Statement. Second, it includes other interstate services provided pursuant to FERC's rules authorizing sales for resale at negotiated rates. NS-PGL Ex. TZ-2.0 at 65.

Peoples Gas points out that it received a Hinshaw Blanket Certificate in March, 1998. The Peoples Gas Light and Coke Company, 82 FERC ¶62,145 (1998). And, the initial Operating Statement which included only transportation services was approved by the FERC in March, 1998. The Peoples Gas Light and Coke Company, 82 FERC ¶61,239 (1998). The FERC approved the filing with storage and parking and loaning services in March 1999. The Peoples Gas Light and Coke Company, 86 FERC ¶61,226 (1999). Service began immediately following the receipt of the operating approval. Id. at 66.

Hub rates associated with the services provided under the Operating Statement are developed and set according to the FERC rules. The most recent rates were established in FERC Docket No. PR07-1-000 and approved by FERC in March, 2007. The Peoples Gas Light and Coke Company, 118 FERC ¶61,203 (2007); *See* also NS-PGL Ex. TZ-2.0 at 66. The rates for the other Hub services are established through negotiations with the counter parties and by means of a competitive bidding process in which the highest bidder wins. Id. at 66; Tr. at 512.

Peoples Gas points out that it has credited to the Rider 2 Gas Charges(or will be crediting following an order in its fiscal 2005 cost reconciliation case), over $20 million in 2005 and 2006 alone, for gross revenues from the Hub. In addition, as part of the resolution of Peoples Gas' fiscal years 2001-2004 Gas Charge case, the Commission determined that issues concerning the treatment of Hub revenues for those years were properly included in the refund that the Commission ordered. Peoples Gas would further note that Hub revenues are forecasted to reach $13 million in 2007. NS-PGL Ex. TZ-2.0 at 69-70; Tr. at 516.

2. Staff

Staff recommends that the Commission order Peoples Gas to cease providing Hub services because the provision of Hub services at Manlove Field is likely to impose costs above revenues upon ratepayers in the coming years. Based on its review, Staff contends that the costs for base gas needed to grow the working inventory gas at Manlove Field are substantial. In this regard, Staff questions the prudency of starting Hub services without a complete analysis and assessment. Peoples Gas examined whether it could expand Manlove Field, but it never estimated the costs, how long it would take, or whether ratepayers would benefit from the expansion.

Staff observes Peoples Gas to assert that there are customer benefits from its provision of Hub Services. And, Staff concedes that Peoples Gas is crediting revenues that are higher than costs currently being incurred. NS-PGL Init. Br. at 102. Still, it argues that these revenues are insufficient to justify continued Hub operations, because in Staff's view, the revenues are likely to be overwhelmed by a need for massive investments in base gas. Staff Init. Br. at 86. Staff witness Rearden's net benefit analysis for "revenues greater than costs" included the costs of base gas, that, have not been realized as yet, but which Staff views as likely to be incurred in the future. Id. at 31.

Further, Staff disputes Peoples Gas claims that the Hub expansion extended Manlove's decline curve and that this extension benefits the ratepayer. Staff Ex. 22.0 at 34-35. According to Staff, Peoples Gas provides no studies or other documentation to support this statement. Notably too, Peoples Gas made the same claim in Docket 01-0707, which the Commission rejected.

Staff also commented on Peoples Gas claim that additional liquidity lowers prices: "[i]ncreasing market liquidity by increasing the supply of gas at the Chicago city gate creates downward pressure on gas prices." NS-PGL Init. Br. at 100. Staff argues that this unsubstantiated statement provides no compelling reason to allow Hub services to continue. In Staff's view, the extent to which the Hub adds 'liquidity' to the market is just not clear. Various publications calculated price indices before the Hub was operational, it notes, so a market already existed. Even if the Hub adds some degree of liquidity to the market, Staff does believe that this necessarily lowers prices. According to Staff, the best that can be said is that additional liquidity lowers transaction costs, which makes the price signal more valuable. But, in Staff's view, prices themselves are determined by the interaction of supply and demand, and additional liquidity, by itself, does not alter that balance.

Staff states that it is only concerned with whether ratepayers are better off with the Hub or without it, i.e., whether the Hub, including all of its associated costs, is prudent. To this end, Staff conducts a net benefits test. If the result is a negative net benefits (Hub benefits are less than its costs), then ratepayers are subsidizing Hub customers, since ratepayers are covering costs caused by Hub customers. Taking into account Staff's view that Peoples Gas may need to inject up to 36 Bcf of base gas Staff calculates that reasonable estimate for the total annual pre-tax cost for base gas is $11.3 million. Id. at 24-25. And, Staff observes that Peoples Gas to calculate its historical expenses at approximately $2.0 million. Id. at 25. On these factors, Staff witness Rearden estimates that the incremental cost of the Manlove Field expansion in 1998 totals approximately $13.3 million. Id. at 26.

Further, in examining the fiscal year Hub revenues over time, Dr. Rearden determined that $10-$12 million was a reasonable estimate for Hub revenues. Id. at 22. He also considered Peoples Gas calculation that $8.9 million out of $10.1 million (88%) of total Hub revenues were directly connected to the Manlove expansion. NS-PGL Ex. TZ-3.6.

Dr. Rearden also tested whether the Hub is prudent beginning from today's situation, given Staff's view about how much base gas Peoples Gas will ultimately have to add to Manlove Field. By Staff's account that totals 45 Bcf and since Peoples Gas has already added about 8 Bcf, it still is potentially liable for an additional estimated 37.4 Bcf. This amount calculates at total annual costs of approximately $16 million. Under this scenario, and owing to Peoples Gas claims that revenues are likely to run to less than $12 million, Staff maintains that the Hub cannot hold ratepayers harmless. Even at that, Staff observes the $4 gas cost to be at the low end of what is reasonable in today's gas market. At higher gas prices, like the $6 and $8 levels that Dr. Rearden considered for his study, the cost to inject base gas into Manlove Field increases and suggests that the Hub is unlikely will be able to pay for itself going forward. Under all the variables used for his study, Staff argues, Dr. Rearden concluded that the Hub is uneconomic for ratepayers. Staff Ex. 24.0 (Corrected) at 27.

Staff claims that, before Peoples Gas expanded Manlove Field, it did not examine the value that the extra capacity might provide to ratepayers as a physical hedge and for peak day deliverability. Rather than using the system to generate Hub revenues, Staff believes that the system could be used to decrease ratepayers' gas costs. In Staff's view, increasing Manlove Field's allocation to ratepayers might enable the Peoples Gas to substitute Manlove Field storage for leased storage and/or transportation services. Staff Ex. 24.0 Corrected at 29.

Staff notes that, in surrebuttal testimony, Peoples Gas did present a study that purported to investigate whether the additional capacity (10.2 Bcf or MMDth) benefitted ratepayers more by using it to offer Hub services or to physically hedge gas for ratepayers. Staff observes this study to reflect Peoples Gas estimate that the physical hedge is worth $9.3 million, while it forecasts Hub storage revenues (those resulting from the expanded Manlove Field) equal to $10 million. In addition, there is the position that, if the 10.2 Bcf (MMDth) additional capacity in Manlove Field can be used to store gas for ratepayers, Peoples Gas must earn a return on the expenditures for the increased gas volumes. NS-PGL Ex. TZ-3.0 at 40.

While the figures derived from the two options are roughly of the same magnitude, Staff does believe them to be directly comparable. According to Staff, revenues of $10 million does not correspond to the total value of Hub storage services to Hub customers, but represents some fraction (not determined, since it is a function of the market) of the value of the physical hedge. In other words, Staff maintains, the physical hedge value is likely to be split between the customer and Peoples Gas as the Hub services provider. In Staff's view, either the $9.3 million amount underestimates the physical hedge, or the Hub revenues of $10 million is not a realistic amount or tied to other years with a different seasonal price differential.

Referring back to the tests it produced, Staff claims to have demonstrated that costs are higher than revenues, and that the revenue shortfall from Hub services will be ultimately borne by ratepayers. As such, Staff argues, Peoples Gas should cease Hub transactions. Id. at 34-35.

Staff notes that City-CUB's main point about the Hub appears to be that Peoples Gas should stop their practice of predetermining a portion of Manlove storage capacity to be used for the Hub before it optimizes its gas supply portfolio. City-CUB Init. Br. at 54. Staff agrees that the Manlove Field's working inventory should not be allocated for Hub Services before determining the optimal allocation to ratepayers. Staff further believes that the total of 7.88 Bcf (MMDth) volume of base gas, valued at $39,019,000 should be denied rate base treatment. In addition, Staff recommends that Peoples Gas' reported Hub expenses should also be disallowed from rates. In Staff's view, these are not shown to be just and reasonable.

Were the Commission to not find any imprudence in the expansion of Manlove Field, Staff claims that the cost associated therewith should still fail recovery. This is so, Staff argues, because Peoples Gas did not obtain prior Commission approval for its actions as required under Section 7-102(E) of the PUA. 220 ILCS 5/7-102(A)(g). Staff claims that a number of legal opinions support its position on the matter. Staff Init. Br. at 64-70.

3. City-CUB

In this proceeding, CUB and the City sponsored the testimony of Jerome Mierzwa of Exeter Associates, Inc., regarding Peoples Gas' provision of Hub services and its operation of Manlove field. They point out that the issues here are essentially identical to the issues Mr. Mierzwa addressed in Peoples Gas' 2005 reconciliation proceeding, i.e., Docket No. 05-0749. City-CUB further point out that, in Docket No. 05-0749, Peoples Gas explained that the amount of Manlove storage it assigns to system supply is based on historical experience and while the utility uses a gas planning dispatch model in its gas supply planning process, it predetermines the 26.3 Bcf of storage it allocates to system supply and excludes the 10.2 Bcf it uses to provide Hub services from its gas dispatch planning model. City-CUB Ex. 3.0 at 4, 7. In Docket No. 05-0749, Mr. Mierzwa recommended that Peoples Gas "should optimize the entirety of Manlove field's storage capacity for ratepayers by including all available storage in the gas dispatch model." *See* Id. at 7.

Here, City-CUB note, the use of Manlove Field for Hub services also is at issue and they observe Staff to recommend that Peoples Gas cease offering such services. Staff Ex. 24.0 REV. at 29. They note too, that Staff recommends that the Commission disallow the $35 million of base gas that Peoples Gas seeks to include in rate base, as well as $2.5 million in operational expenses. Id. at 25.

If Hub services were no longer offered, City-CUB point out, sales customers would no longer be credited for the approximately $10 million in Hub revenues in any future purchase gas adjustment ("PGA") proceedings. City-CUB further raise the point that, if the Commission were to determine that Hub services should be terminated, it will need to decide the appropriate disposition or use of the 10.2 Bcf of working gas currently assigned to the Hub.

For their part, City-CUB recommend that the Commission preserve, in this proceeding, its ability to determine the extent to which Manlove storage should be used to serve system supply in gas cost reconciliation proceedings – both current and future. While they take no position on Staff's recommendations with regard to the Hub, City-CUB ask the Commission not to foreclose options for the use or disposition of that asset before PGL completes an optimization study that is not compromised by a predetermined assignment of capacity to the Hub. That determination is best made, they argue, in the context of Peoples Gas' pending and future PGA proceedings.

Essentially, City-CUB want Peoples Gas to optimize storage for ratepayers. As such, they contend that Peoples Gas's practice of predetermining a portion of Manlove storage capacity to be used for Hub services is not reasonable because it denies ratepayers the full potential benefits of the storage capacity for which they pay in base rates. City-CUB Ex. 3.0 at 7. Their witness, Mr. Mierzwa testified that, "[a]ll else being equal, theoretically, the more storage available to a gas utility, the lower the utility's gas costs." Id. at 5. Further in his testimony, City-CUB observe, Mr. Mierzwa demonstrated that in using the current seasonal difference in gas prices as reflected on the New York Mercantile Exchange ("NYMEX") of approximately $1.20 per Dth, Peoples Gas could potentially reduce its gas costs by $12.24 million by taking advantage of the seasonal differences in gas prices. City-CUB Ex. 3.0 at 6. This calculation, they note assumes that the entire 10.2 Bcf currently assigned to Hub services were utilized for system supply. As another alternative, City-CUB note, Mr. Mierzwa calculated the effect of using the 10.2 Bcf of Manlove capacity currently assigned to Hub services to displace the same amount of leased storage. Id. at 6. His work (reflected in City-CUB Ex. 3.2), demonstrates that, since Peoples Gas currently purchases 33.5 Bcf of contract storage service from interstate pipelines at an average cost of approximately $1.00 per Dth, the

Company could potentially reduce its gas costs by $10.5 million if it used existing Manlove storage assets instead. Id.

City-CUB observe that Utilities' witness Zack disputed Mr. Mierzwa's calculations, averring that (1) his calculation of using the entirety of Manlove for ratepayer gas excludes inventory costs of the additional 10.2 Bcf of gas inventory which, if applied, would reduce his estimate of savings by $4.96 million for a net ratepayer benefit of $7.28 million; and (2) the displacement of leased storage inaccurately assumes a one-for-one replacement. NS-PGL Ex. TZ-3.0 at 45-46. And, Mr. Zack further claimed that leased storage provides additional benefits in the form of injection and withdrawal flexibility. Id. at 40-41. According to City-CUB, however, Mr. Zack's criticisms ignore Mr. Mierzwa's qualification that, while the entire 10.2 Bcf of Manlove storage assigned to Hub services cannot provide both a $12.24 million seasonal price benefit and a $10.5 million reduction to contract storage costs, the 10.2 Bcf could be used to partially obtain both benefits. For example, he indicated that 5.0 Bcf of Manlove storage could be used to provide a seasonal price benefit, while 5.2 Bcf could be utilized to displace contract storage. City-CUB Ex. 3.0 at 6.

To be clear, City-CUB point out that Mr. Mierzwa did not recommend that all of the Manlove storage currently used to support Hub services should be assigned to system supply - only that the amount of Manlove storage assigned to system supply should be determined by the utility's gas dispatch model. Id. at 7. So too, they argue, the purpose of Mr. Mierzwa's analyses was not to show that the entirety of Manlove should be used for system supply or to determine a disallowance, but only to support the premise that the optimal amount of storage should be determined through Peoples Gas' existing gas dispatch planning model, rather than being predetermined. Id. at 7.

City-CUB recognize that any revenues Peoples Gas receives by providing Hub services flow through the gas charge. And, they note Mr. Zack to claim that, during each of 2005 and 2006, Hub revenues exceeded $10 million. NS-PGL Ex. TZ-2.0 at 70. Their witness Mr. Mierzwa testified in the 2005 reconciliation period at issue in Docket No. 05-0749 that Hub revenues exceeded the increase in gas costs for sales customers that resulted from the reservation of Manlove storage capacity for Hub services. Docket No. 05-0749; City-CUB Ex. 1.0 at 9.

Under City-CUB's suggested approach, Peoples Gas could continue to utilize Manlove Field to provide Hub services, and thus any future revenues from those services would continue to flow through the gas charge and customers would continue to receive that benefit. Their only argument is that Peoples Gas does not justify its practice of eliminating the 10.2 Bcf of gas reserved for Hub services from the gas dispatch planning model. Therefore, these parties recommend that the Commission require Peoples Gas to optimize the entirety of Manlove Field's storage capacity for ratepayers by including all available storage in the gas dispatch model. This, they argue, will have the effect of reducing gas costs for ratepayers.

In response to concerns about the use and cost of the Hub, City-CUB note Mr. Zack to have considered three options that "represent the opportunity cost of the Hub."

NS-PGL Ex. TZ-3.0 at 39. First, he indicated that Peoples Gas could eliminate the 10.2 Bcf currently assigned to Hub services altogether and return field operations to a 26 Bcf annual cycle. Id. Second, he considered that the Company could use some or all of the 10.2 Bcf of Hub capacity for customers without reducing any leased storage. Id. Third, he explained that the Company could use some or all of the 10.2 Bcf of Hub capacity for customers, while also reducing, as possible, any uneconomic, leased storage. Id. It is this third option, City-CUB point out, that most closely resembles what their witness Mierzwa is recommending both in this proceeding, and in testimony for Docket No. 05-0749.

With respect to this third option, City-CUB note Mr. Zack's testimony stating that costs and savings would be more difficult to quantify under the third option than under the other options. Id. at 40. But, he also stated that Peoples Gas plans to conduct analyses with regard to determining the most economic use of Manlove storage and the Hub for the benefit of ratepayers. Tr. at 540. And, Mr. Zack further set out that the gas dispatch model would be made part of this analysis. Id. at 541. According to City-CUB, the whole of these affirmative statements, favorably address the very issues they have identified. In the end, they assert, if the Commission directs Peoples Gas to conduct the analyses described by Mr. Zack during his cross-examination, i.e., to use the gas dispatch model to optimize use of Manlove field on behalf of its sales customers, City-CUB's concerns regarding the appropriate use of the storage field in both the instant dockets and Docket No. 05-0749 may be resolved.

4. Peoples Gas' Response

Peoples Gas observes Staff to argue that it was imprudent for Peoples Gas to offer Hub services and that the cost of expanding the Hub services should not be recovered in rates because Peoples Gas never conducted written studies to determine the prudence of expanding of Manlove Field and never received prior approval from the Commission pursuant to Section 7-102(A)(g) of the PUA before expanding the Hub.

Contrary to what Staff contends, Peoples Gas maintains that the evidence amply demonstrates that the customer benefits provided by the Hub have exceeded, and are expected to continue to exceed, the costs of providing the service. NS-PGL Ex. TZ-2.0, NS-PGL Ex. TZ-3.0 REV. The Hub operation in the fiscal 2006 test year, it points out, brought $10 million in revenues (all credited to the Gas Charge) against an annual revenue requirement of $3.3 million. NS-PGL Ex. TZ-2.0 at 71. Surely, PG argues, this is not the result of imprudence.

Peoples Gas explains that it offers Hub service as a means to more efficiently utilize the existing Manlove Field and Mahomet pipeline assets and to provide customer benefits. Indeed, Peoples Gas asserts, Hub services provide customer benefits in three ways: (1) through credits to the Gas Charge (as discussed above); (2) by extending the Manlove decline point (as defined below); and (3) by increasing market liquidity at the Chicago citygate. NS-PGL Ex. TZ-2.0 at 66.

Peoples Gas explains why it is beneficial that the additional Hub volumes serve to extend the decline point. According to the Utility, extending the decline point of

Manlove means extending the capability of the field to perform full peak withdrawal throughout the winter season. The operation of the Hub causes the injection of more gas into Manlove Field, which extends the field decline point and this, in turn, extends how long into the withdrawal season Manlove Field is useful for storage and capable of full peak withdrawal. Since all Hub volumes are contractually required to be withdrawn, Peoples Gas notes, these bring with them the benefit of the higher volumes without the risks associated with a warm winter. NS-PGL Ex. TLP-2.0 at 13.

To verify the Manlove Field decline point, Peoples Gas notes that a report prepared by Roxar, Inc., in July, 1999 shows the decline point extending as working gas is increased. NS-PGL Ex. TLP-2.9. Also, Peoples Gas points to the 2003 and 2005 Connaugton Reports, each of which contain a discussion of the extension of the decline point. NS-PGL Ex. TLP-2.0 at 14; PGL Ex. TLP-1.1. The critical benefit to ratepayers from this feature, Peoples Gas argues, is well supported and comes in the form of access to the full daily peak withdrawal capability of Manlove Field longer into the winter season.

Contrary to what Staff would suggest, Peoples Gas notes that the Commission never did find that the decline point had not been extended through the additional gas associated with the Hub, nor did it make any finding regarding whether the decline point extension was an operational benefit. Peoples Gas explains that the Commission's finding on the decline point was that the additional gas which supported the decline point extension did not directly benefit customers because the profits from the third party services were not being passed to customers. Docket No. 01-0707, Final Order at 93 (March 20, 1996).

Still another benefit from Hub, Peoples Gas argues, flows from its increasing market liquidity at the city gate specifically and more generally in the Chicago area market. According to Peoples Gas, all the gas supporting Hub activity must come to one of Peoples Gas' city-gate locations to be a Hub transaction. This increases the amount of gas delivered to Peoples Gas on a daily basis. The more gas brought to the Chicago city gate as a result of the operation of the Hub, PG maintains, the greater the benefit to all customers. This activity provides all customers access to a greater amount of gas than would otherwise be available if there was no Hub activity. NS-PGL Ex. TZ-2.0 at 70. Increasing market liquidity, Peoples Gas asserts, creates downward pressure on gas prices.

Since coming into existence, all of Hub expenses, including and consisting primarily of over $7 million of incremental compressor fuel costs have been borne by Peoples Gas. Peoples Gas emphasizes that none of these costs were paid by Peoples Gas' customers. Id. at 69. Peoples Gas explains that the Hub rate design included Manlove Field's base gas requirements and these costs were included in the cost of service study used to support the Hub filing before the FERC. The Peoples Gas Light and Coke Company, 82 FERC ¶ 62, 145 (1998); 82 FERC ¶ 61, 239 (1998); 86 FERC ¶ 61, 266 (1999); 118 FERC ¶61,203 (2007). These costs were then used to develop the rates for Hub services under the Operating Statement. Id. at 68. Peoples Gas flatly states that the expansion of Manlove Field did not involve the use of Gas Charge assets or the use of assets in which costs were being recovered through base rates. All incremental expenses associated with the Hub, the Utility notes, were absorbed by Peoples Gas. NS-PGL Ex. TZ-2.0 at 67.

Peoples Gas points out that the storage expansion for the Hub began years after Peoples Gas' last rate case. Thus, the base rates approved in Peoples Gas' last rate case proceeding, i.e., Docket No. 95-0032, reflected a test year that was prior to the expansion of Manlove Field. Id. *See* also NS-PGL Ex. VG-2.0 at 57. As such, Peoples Gas seeks to recover these costs through the instant rate hearing.

Peoples Gas considers Staff's proposed disallowance of all costs associated with the Hub to be improper. It observes Staff witness Rearden to recognize that the Hub revenues are estimated to be \$10-\$12 million per year. Staff Ex. 12.0 at 22. By use of an improper methodology, Peoples Gas argues, Dr. Rearden concluded that Hub costs per year were \$13.3 million, as being made up of the capital costs of the supposed additional cushion gas, and operations and maintenance expense. Id. at 12. Since \$13.3 million is more than \$10-\$12 million, he concluded that the Hub is imprudent. Even if it were possible to accept Dr. Rearden's figures, which Peoples Gas does not, the revenue requirement should only be reduced by \$1.3 million to \$3.3 million per year, as this represents the difference between the cost of \$13.3 million and the revenues of \$10-\$12 million dollars. Yet, Peoples Gas observes that Dr. Rearden would eliminate all the rate base and operations and maintenance expense associated with the Hub, while at the same time leaving in all the revenues to reduce future gas costs. Id. at 30. If the Commission were to find the Hub imprudent, Peoples Gas asserts, then the only proper result is to reduce the revenue requirement no more than \$1.3 – \$3.3 million. *See* NS-PGL Ex. 2.0 at 71. When imprudence is found, Peoples Gas argues, only its incremental impact, if any, is disallowed. In re Central Ill. Light Co., Docket No. 94-0040, Order (December 12, 1994).

Peoples Gas states that, prior to the Commission's final order in Docket No. 01-0707, all the costs and revenues associated with the Hub and the base rate assets that support the Hub are accounted for above the line. Subsequent to the Docket No. 01-0707 order, however, all the revenues were flowed through the Gas Charge. NS-PGL Ex. TZ-2.0 at 70. Since the Hub came into existence, PG emphasizes, all of its expenses, including and consisting primarily of over \$7 million of incremental compressor fuel costs have been borne by Peoples Gas and none of these costs were paid by Peoples Gas' customers. Id. at 69. Peoples Gas maintains that the only incremental capital cost attributable to the Hub is for cushion gas which is discussed in arguments on Manlove Field.

Peoples Gas maintains that the customer benefits provided by the Hub have exceeded, and are expected to continue to exceed, the costs of providing these services. For this reason, Peoples Gas asserts, it should continue to provide Hub services for the benefit of its customers. NS-PGL Ex. TZ-3.0 Revised at 43. When asked what a net benefit to ratepayers is as it pertains to the Hub, Staff Witness Dr. Rearden's response was, "[r]evenues of – either cost savings or revenues greater than costs". Tr. at 674. Using Staff's simple definition, Peoples Gas believes it clear that Hub operations are a net benefit to the Peoples Gas system and its ratepayers.

Peoples Gas observes Staff to claim that cost recovery should be barred owing to Peoples Gas' failure in obtaining the approval required by Section 7-102(A)(g) of the Act. For its part, Peoples Gas maintains that its provision of Hub services did not require approval action under Section 7-102(A)(g). The plain language and specific terms of this statute, Peoples Gas asserts, simply do not apply. While Staff attempts to suggest that Hub services are unconnected to "the business of such public utility" in order to have the statute apply, Peoples Gas strongly disagrees and explains why. If Hub services were not part of the utility business, Peoples Gas argues, it seems unlikely that the Commission could or would have ordered revenues to go to utility customers through the Gas Charge. But, Peoples Gas points out, that is precisely what the Commission did in the Peoples Gas 2001 Reconciliation docket.

Peoples Gas notes too, that Hub services were no secret and certainly not to Staff, and it details Staff's involvement in matters over the years which reflects that full and long-time knowledge. Further, Peoples Gas argues, all of the case authority on which Staff relies can be easily distinguished because the facts and circumstances here are much different. In short, it takes issue with Staff's position.

Peoples Gas observes Staff to contend that Peoples Gas has failed to prove that its costs of operating the Hub are just and reasonable, such that those costs should be removed from Peoples Gas' rate base. It is well-established on record, Peoples Gas asserts, that the Hub is a net benefit to the utilities' customers. Its costs are prudently incurred and are used and useful in serving customers.

5. Commission Analysis and Conclusion

On the whole of the record before us, and on this date, the Commission is unable to find that the expansion of Manlove Field is imprudent. We have already considered that Peoples Gas has been injecting base gas in amounts sufficient to support Manlove Field's operation and this includes storage for sales customers, services to its transportation customers and FERC-jurisdictional Hub operations. There is no evidence to persuade us otherwise.

Staff's position that Hub services are imprudent and its conclusions in the matter are based upon what derives from its net benefits test. While we understand that such an analysis is useful and telling, we also believe that it must be conducted properly and fairly. All the tests we see here begin with the same faulty premise, i.e., the unproven fact that Manlove Field needed (in 1998), or needs today, 45 Bcf of base gas. In other words, Staff's arguments as well as the inputs for its calculations rely on speculation that massive amounts of base gas into Manlove will be needed in the future. We cannot accept that assumption, however, because the evidence today does not reveal this to be fact. So all we have for the net benefits analysis are a series of sterile mathematical calculations neither grounded in observation of performance nor aided by the requisite scientific expertise. This type of analysis will not serve us in these premises and must be rejected. The bottom line is that we do not find the imprudence on which Staff hinges its position.

Considering all of the relevant evidence at hand, the Commission is persuaded that, at this time, the Hub provides more benefits than costs. We come to this conclusion by examining all of the relevant evidence. The record shows that Hub revenues have exceeded $10 million annually and they are expected to exceed that amount in 2007. NS-PGL Ex. TZ-2.0 at 70. It is uncontested that, pursuant to the Commission' Order in Docket 01-0707, all revenues from Hub services are credited to Peoples Gas' customers through reductions its Rider 2 Gas Charges, including a gross $20 million in 2005 and 2006 and a forecasted gross $13 million in 2007. NS-PGL Init. Br. at 99. And, the Commission is compelled by the record to find that Peoples Gas has and is complying with our order by crediting to Rider 2 gross revenues from the Hub. In light of this monetary benefit, the Commission believes that it would be harmful to customers to eliminate the Hub.

Other evidence leads the Commission to conclude that the Hub benefits Peoples Gas' customers in a less direct but equally meaningful way. As such, Peoples Gas informs that additional Hub volumes serve to extend the decline point at Manlove Field and this enables the field to perform better. While Staff claims that this attribute is not supported, we find that independent studies of record, i.e., the Roxar, Inc., report of 1999 and the Connaugton Reports of 2003 and 2005, have not been challenged, and these indicate an extension of the decline point. On this evidence, the Commission is persuaded that the extension of the Manlove Field decline point is a benefit of Hub and this benefit is extends to all customers of Peoples Gas.

The Commission also considers the assertion that the Hub activity increase liquidity at the Chicago-city gate and as a result of such activity and the availability of more volumes of gas, there is a theoretical downward pressure on gas prices due to the Hub activity. While Staff disagrees, the evidence does suggests there being some likelihood of downward pressure created because of Hub activity and from this we gather there is benefit to all customers.

The Commission also observes that under a proper allocation of the cost of the base gas supporting Hub operations, the Hub's revenues easily exceed costs. NS-PGL Ex. TZ-2.07. We are mindful that the cost of base gas is shared by Hub customers, but all of the revenues are being credited to the customers through the Purchased Gas Adjustment. NS-PGL Ex. TZ 2.0 at 68. Staff would minimize this tangible benefit that even all of the GCI parties acknowledge to exist.

There is not, nor can there be, any concern of Gas Charge assets being used to subsidize Hub services. The record makes clear and it is unchallenged that all of the Hub expenses, including and consisting primarily of over $7 million of incremental compressor fuel costs have been borne by Peoples Gas. None of those costs are recovered through the Gas Charge and none were paid by Peoples Gas' customers. NS-PGL Ex. TZ-2.0 at 69. The Commission finds the record devoid of any evidence that Peoples Gas has utilized any of the Gas Charge assets to subsidize Hub services. We observe too, that the storage expansion for the Hub began years after Peoples Gas' last rate case. As such, the base rates approved in Peoples Gas' last rate case proceeding, i.e., Docket No. 95-0032, reflected a test year that preceded the expansion of Manlove Field.

Staff recommends that the base gas cost of $39,018,791.41 that Peoples Gas is proposing be wholly disallowed. In addition, Staff recommends that the Utility's reported

Hub expenses also be disallowed. In other words, Staff would assign all revenues to ratepayers and none of the reasonable costs incurred. We are not comfortable with this one-sided view. So too, Staff's proposed disallowance lacks clarity and conviction. In large part, the premise of Staff's entire argument is that Peoples Gas *has not injected enough base gas* into Manlove Field. At the same time, however, Staff's proposed disallowance would have Peoples Gas not put *any* base gas into rate base. There is a fundamental inconsistency here that cannot be reconciled. It amounts to overreaching.

Recognizing that the Commission might not find imprudence in the decision to expand Manlove Field for Hub services, Staff argues that Peoples Gas' failure to apply for Section 7-102(A)(g) should result in the denial of cost recovery. We do not agree.

The Commission seriously questions that Peoples Gas was required to acquire prior approval to expand working gas at Manlove Field. As we read Section 7-102(A)(g) of the Act, a public utility must obtain approval from the Commission before it may employ its public utility resources in "any business or enterprise" that is not "essentially" and directly connected with or a proper department of division of the utility business. This statute would only be applicable to the Hub if it were unconnected to distribution, storage and sale of gas, i.e., "the business of such public utility." Based on what is on record, that is not the situation here.

We need not bother with a full statutory construction because there is more at hand and it is of dispositive legal significance. Staff fails to recognize that the Commission took close consideration of Peoples Gas' Hub services in Docket No. 01-0707. In that proceeding, we issued certain directives to the Utility as to the proper accounting for the costs and revenues. By our actions, the Commission has effectively provided approval and both we, and People Gas, are bound to that Order in Docket No. 01-0707. Considered in still another way, our actions amount to a waiver of approval as is also within the authority that Section 7-102(A) provides.

We observe that during fiscal years 1997 through 2006, Peoples Gas capitalized an additional 7.88 MMDth of injections as cushion gas into Manlove Field, at a cost of $39,019,000, which it now proposes to include in rate base. Id. at 11. We further note that Peoples Gas has estimated that the amount of cushion gas attributable to Hub services is 1.34MMDth. In the final analysis, the Commission concludes that $39,019,000 will be included in rate base together with $2,533,000 of operations and maintenance expense.

C. Hub Procedures - Manlove Capacity Standards

1. Staff

Staff raises a concern that Peoples Gas has increased its leased storage capacity volumes while at the same time reducing its own allocation of Manlove storage capacity in favor of the Hub. Staff Ex. 23.0 at 14. On the basis of this account, Staff recommended that Peoples Gas develop procedures to document how it allocates capacity from the Manlove storage field and how it ensures that rate payers are not harmed by its decision. Id. Staff further recommended that Peoples Gas provide this information to the Director of the Energy Division within 60 days of the Commission's Final Order in this proceeding. Id.

2. Peoples Gas

Peoples Gas agreed to Staff's proposal, but it requested 120 days instead of the 60 days recommended by Staff. NS-PGL Ex. TEZ-3.0 at 38. It notes that this date change is acceptable to Staff. Thus, Peoples Gas observes, it is uncontested that it will provide to the Director of the Energy Division within 120 days of the Commission's Final Order in this proceeding, procedures to document how it allocates capacity from the Manlove storage field and how it ensures that rate payers are not harmed by its decision.

3. City-CUB

In their joint brief**,** City-CUB note with particularity the testimony of Peoples Gas witness Zack and his statement that the Utility plans to conduct analyses with regard to determining the most economic use of Manlove storage and the Hub for the benefit of ratepayers. They further point to Mr. Zack's claim that the gas dispatch model would be made part of this analysis. Id. at 541. These parties explain to the Commission that if Peoples Gas were directed and required to conduct the analyses described by Mr. Zack, i.e., using the gas dispatch model to optimize use of Manlove field on behalf of its sales customers, City-CUB's concerns about the appropriate use of the storage field would be resolved.

4. AG Position

The AG recognizes that while the Commission typically does not dictate the precise way in which utility assets are to be utilized, some involvement appears to be required in this situation. In particular, the AG observes City and CUB to have identified that use of Manlove Field as a way to reduce gas costs for ratepayers has never been sufficiently analyzed. At the heart of the AG's proposal is to have Peoples Gas explore the possibility of devoting the entirety of Manlove field to sales customer service; or using some capacity for sales customers while also reducing leased storage; or using some Hub capacity for sales customers without reducing leased storage. According to the AG, these are the same concepts that the City and CUB support. In addition, the AG would have the Utility consider whether the gas dispatch model or another mechanism will better optimize ratepayer interests.

Further, the AG asserts, that Peoples Gas should continue to account for all Hub revenues and non-tariff revenues in accordance with the Commission's order in Docket No. 01-0707, and in compliance with 83 Ill. Admin Code 525.40(d), unless and until ordered to do otherwise by the Commission.

5. Commission Analysis and Conclusion

Based on the recommendations of Staff, the Commission orders Peoples Gas to submit to the Director of the Energy Division, a report of procedures to document how Peoples Gas allocates Manlove storage capacity; how it ensures that ratepayers are not harmed by its allocation decisions; and, how it will use the gas dispatch model to optimize use of Manlove Field on behalf of its sales customers.

Everything that is set out by the City-CUB and the AG tells us that Staff's proposal is reasonable and necessary to satisfy all of the GCI parties' concerns in these premises. As agreed to between Staff and Peoples Gas, this document will be submitted by the Utility no later than one hundred-twenty (120) days from the date of the Commission's final Order in this proceeding.

After Staff completes its review, it will inform the Commission further.

D. Hub Revenue Distribution Proposal

1. Vanguard, RGS, IIEC.

In their respective briefs, Vanguard, RGS, and IIEC maintain that Hub revenues should not be credited solely to sales customers, i.e., PGA customers. Taken as a whole, the issues they raise are whether the Utilities should credit transportation customers and "Choices For You" customers with the benefit of Hub revenues. No testimony in support of their respective positions is on record.

2. Peoples Gas

Peoples Gas takes no position on the matter and is willing to dispose of the revenues as directed by the Commission so long as this direction is clear and unambiguous. Peoples Gas notes, however, that it would need to develop a mechanism to accommodate a change in the status quo. In this respect, Peoples Gas asks to be able to develop a mechanism similar to that it understands NICOR Gas to have in place with modification to fit within its Gas Rider 2.

3. Staff

Staff informs that it has some concerns with the merits of the pending proposal. It further explains that, because the issues only surfaced on brief, Staff and other parties had no opportunity to offer testimony in the matter. Staff believes that arguments at hand are inadequate for full consideration of the issue.

4. Commission Analysis and Conclusion

The Commission believes that the instant proposals are not properly supported on the record by either testimony or analysis. Nor can we assume that that these proposals are undisputed. Indeed, Staff tells us that it has some concerns. And, we have not heard from all interested parties on the issues. The Commission will not presume acquiescence by silence in these premises. Even if we were to do so, it is clear and obvious that an appropriate record does not exist. As such, the Commission has neither the evidence nor the arguments necessary to arrive at a full and reasonable determination. This is particularly so when the proposal is such that it would upset the rulings we made in a prior order, i.e., Docket No. 01-0707.

Nothing we say here reflects on the merits of the respective proposals. In the final analysis, we agree with Staff that Vanguard, RGS and IIEC are free to bring these proposals in a future proceeding and in manner that will allow for full litigation of the issues by all interested parties.

VI. WEATHER NORMALIZATION – AVERAGING PERIOD

A. Parties' Positions and Applicable Law

To set rates for a gas utility, the Commission must determine (*via* estimate, for future years) the number of "heating degree days" ("HDDs") during which those rates will likely be collected annually. An HDD is not a calendar day. Rather, it is a unit of time in which ambient weather will likely cause customers to consume gas for heating.[24] The colder the weather in a year's span, the more HDDs will accumulate in that year. The more HDDs accumulate, the more therms the utility will deliver and the more revenue the utility will collect. Thus, the Commission uses an HDD estimate to calculate the amount the utility should be permitted to charge per unit of consumed gas, so that the utility will be likely to collect its allowed return (insofar is that return is collected through volumetric charges). If HDDs (cold weather units) are overestimated in rate-making, the utility's volumetric rates will be too low and the utility may under-earn. If HDDs are underestimated, those rates will be too high, potentially causing over-earning.

A central principle for estimating HDDs is weather normalization. The objective is to determine the level of heating degree days in a typical or "normal" year in which the rates will apply. The Utilities propose that two contentious principles be included in the weather normalization process in these proceedings: 1) that the climate of northern Illinois is warming, with the likely consequence that a normal year will contain fewer HDDs in the future than in the past; and 2) that ten years (averaged) of recent weather history will be more representative of future normal weather than will thirty years (averaged) of recent weather history.[25] The AG and City-CUB challenge the inferences that the Utilities draw from the former proposition, and they disagree with the latter proposition.

With respect to northern Illinois' climate, the Utilities' climate science witness, Dr. Takle, describes a scientific consensus that warming is occurring. Consequently, the Utilities maintain, normal climate in the near future will be more accurately projected by data from a shorter (i.e., ten year) recent time frame than a longer (i.e., thirty year) frame "which has many years of data from the less relevant colder regime." NS-PGL Init. Br. at 106. However, both the AG and City-CUB emphasize Dr. Takle's acknowledgement, at Tr. 850, that a general warming trend does not preclude recurrence of colder winter weather. *E.g.*, AG Init. Br. at 22. Indeed, these intervenors

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[24] Technically, the number of HDDs is the number of degrees Fahrenheit that actual mean daily temperature is below 65 degrees Fahrenheit. NS-PGL Ex. EST-1.0 at 7.
[25] In either case, weather statistics would be derived from the weather station at Chicago's O'Hare Airport.

note, in February 2007, Chicago experienced its coldest weather in 112 years. Id. at 22.

Regarding their proposed use of a recent ten year (rather than a thirty year) period of weather data for weather normalization (specifically, the ten years from 1997 through 2006), the Utilities cite the most recent Nicor Gas rate case[26], in which we approved the use of a ten-year average of HDDs for the Nicor Gas service territory directly adjacent to the Utilities' territories. Additionally (and independently of our decision in Nicor) the Utilities argue that the evidence in this docket proves that "compared to using an average of the past thirty years, an average of the past ten years will more accurately predict the [HDDs] over the next several years." NS-PGL Init. Br. at 105. The Utilities rely on the analysis of their witness, Mr. Marozas, who concluded, "using all available data since the O'Hare weather station began collecting statistics…that using a rolling ten-year average produces less error than a thirty-year average in predicting the next year out, as well as year two, three, four, and five." Id. at 107. The Utilities' preferred ten year average of HDDs, from 1997 through 2006, is 6044 per year. NS-PGL Ex. BMM-1.0 at 7, Table 2. The corresponding thirty year average (i.e., through 2006) is 6401 HDDs. NS-PGL Ex. EST-1.0 at 28.

The AG counters that the appropriate task here is to discern normal climate, not to predict weather, and that "30-year data does a better job of describing a climate." AG Init. Br. at 21. Therefore, the AG maintains, "most jurisdictions around the country" use a thirty year average of HDDs obtained from the federal National Oceanic and Atmospheric Administration ("NOAA"). However, Dr. Takle opines that the NOAA long-term thirty-year average is a particularly poor predictor, citing a climatological study supporting this opinion. NS-PGL Ex. EST-2.0 at 5-6.

City-CUB assert that the Utilities' proposed ten year weather data sample is simply too short to accurately reflect the relevant climate without statistical distortion. Moreover, City-CUB note, the particular ten year period (1997-2006) the Utilities have chosen in this instance conveniently avoids two years of especially harsh weather (1996 and 2007).

Furthermore, City-CUB contend, even if a period shorter than thirty years were appropriate for the normalization process, the Utilities' own analysis shows that their chosen ten year interval is far from the most accurate predictor of future weather conditions. Citing PGL Ex. BMM-1.0, Fig. 1, City-CUB emphasize that 8-, 11- and 12-year data periods predicted subsequent weather more accurately. Both Chicago and the AG point to PGL witness Marozas's testimony that a ten year interval was selected, in part, for "rounding purposes." AG Init. Br. at 23.

With respect to our approval of a ten year normalization interval in Nicor (Docket No. 04-0779 (Sept. 20, 2005)), both the AG and Chicago highlight the following language in our Order: "No analysis of HDD data has been provided to indicate that the ten-year period proposed by Nicor should not be used." Nicor, at 57. Therefore, the intervenors contend, Nicor is distinguishable from the present case, in which they have analyzed and criticized, with record evidence, the accuracy of the Utilities' ten year

[26] Nicor, Docket No. 04-0779, Order at 57 (Sept. 20, 2005).

weather normalization. The AG adds the more general principle that Commission decisions are not *res judicata*, allowing us to treat each case on its individual facts. AG Init. Br. at 27. City-CUB invoke the corresponding principle that deviation from prior Commission practice, without sufficient record evidence, would be arbitrary and capricious. City-CUB apparently believe that the practice of using thirty years of data remains intact after Nicor.

Also, both City-CUB and the AG question the necessity in these particular proceedings for any deviation from the pre-Nicor practice of using thirty years of weather data, given that the Utilities have earned their allowed return in almost all the years since their previous rate case.

In lieu of the Utilities' proposed ten year HDD data, the AG recommends "[u]se of the most recent 30-year average of HDDs." AG Init. Br. at 28. City-CUB recommends that the Commission utilize either the most recent thirty year period (presumably, 1978-2007) or NOAA's thirty year data (derived from 1971-2000).

Alternatively, City-CUB suggest, if the Commission's confidence in thirty year normalization has waned, that we open a proceeding to develop a single, balanced HDD projection methodology that will be consistently employed in Illinois ratemaking. City-CUB and the AG warn that adoption of the Utilities' ten year normalization in this case will simply encourage other gas utilities to propose unique HDD data periods. AG Init. Br. at 24. The likely outcome, as these parties see it, would be inconsistent HDD forecasts for utilities within the same climate region. The Commission notes, however, that inconsistency in HDD forecasts is inevitable unless utilities use the same data source (such as NOAA), the same number of years and the same starting and ending years in their respective forecasts. If utilities initiate their rate cases in different years, they are unlikely to use the same starting and ending years for their forecasts, even if they use the same total number of years (whether ten, thirty or some other)[27]. Thus, to avoid inconsistency, the Commission would have to establish a standard HDD input for all gas utilities, either statewide or within separate climate regions.

B. Commission Conclusion

Our overarching objective is to set rates with the greatest likelihood of generating the Utilities' allowed annual revenues. To achieve that objective, we have endeavored - due to the correlation between cold weather and gas consumption - to include in prospective rates a factor that numerically represents the ambient conditions typically experienced in northern Illinois. Although we have described such conditions as "normal" (and refer to this process as weather "normalization"), the term can be misleading. Any ambient condition is "normal" if it has, in fact, occurred within a climatic area. But for ratemaking purposes, our target has been those conditions (initially quantified in degrees Fahrenheit, then re-quantified in HDDs) that have *most typically* occurred within the climatic area over any year's time, which we have believed would

[27] For example, Nicor's 10-year data yielded an annual HDD average of 5830, and its thirty year average was 6072 HDDs. Nicor at 53. The Utilities, also using ten year and thirty year data sets here, generated 6044-HDD and 6401-HDD averages, respectively.

most likely occur in subsequent years. We have traditionally used an average for this purpose. That average has been derived (until Nicor) from all the ambient conditions that have occurred within a selected period of thirty preceding years. Thus, we have neither tried to predict weather (what *will* happen in the next several years) nor, as City-CUB state, capture the full range of weather regularly experienced in northern Illinois, except insofar as a "full range"[28] of weather contributes to the calculation of past average weather (which has been our proxy for the most likely ambient conditions, with which rates are calculated). Rather, we have taken an average from the past and assumed that it would recur, over time, in the future.

As the Commission views it, the Utilities are proposing a different, and *predictive,* approach. Rather than quantifying the HDDs that are most likely to arise annually in northern Illinois, the Utilities attempt to identify the period of preceding years that, when averaged, has the highest *predictive* accuracy with respect to subsequent years. Although the Utilities, in response to intervenor criticism, have tried to avoid that characterization, e.g., NS-PGL Rep. Br. at 80, they need not have done so. As Nicor demonstrates, we are no longer mechanically resorting to thirty years of data to accomplish our ratemaking objectives through averaging. The critical question is whether the Utilities' proposed predictive methodology is (at the least) no less likely than our traditional thirty year average to match allowed revenues to actual revenues.

Utility witness Marozas establishes that periods of 8, 12, 11 and 10 years of weather data have (in descending order) greater *predictive* accuracy than do thirty years of data, and that those four data sets are more predictively accurate than any other period between one and thirty years (including both the most recent thirty years (through 2006) and the 30 years ending in the year 2000, used by NOAA). NS-PGL Ex. BMM-3.0 at 4. He also demonstrates that ten years of data are more accurate than thirty years when predicting weather within each of the five subsequent years. Id. Utility witness Takle puts those predictive results in the context of global warming and the upward trend of temperatures in northern Illinois, concluding that the last ten years of weather data are more representative of the region's climatic conditions than the last thirty years of data. This presumably explains why shorter data sets have shown greater predictive accuracy than thirty year sets in the recent years studied by the parties here.

Based on the foregoing evidence, the Commission is willing to approve the Utilities' predictive approach for setting rates in these dockets. While our traditional "most likely ambient conditions" formula, based on thirty years of data, has not prevented the Utilities from earning their allowed return in most years, that does not mean that it was ever an optimal mechanism, or that it remains so today. To the contrary, the Utilities' evidence suggests that it was sub-optimal, and getting more so in an incrementally warming climate. *E.g*., NS-PGL Ex. BMM-1.0 at 4. Thus, while we would have expected thirty year data (based on the general statistical principle that more data regarding varying conditions is better than less) to identify the ambient

[28] Neither the record here nor our previous Orders address whether thirty years necessarily encompass the "full range" of northern Illinois weather. What is known is that the National Weather Service uses thirty years, ending in the most recently completed decade, for normalization. NS-PGL Ex. EST-1.0 at 28.

conditions most likely to occur, record evidence does not show that such conditions, in fact, occurred with sufficient frequency to adhere to past methodology. It should be kept in mind that we are asking weather data to do something they were not gathered for - to match actual future revenue to allowed future revenue, over an indeterminate period of years. In Nicor and in the present cases, we have been prodded to improve this process. The Utilities' predictive scheme appears to be an improvement and we will adopt it and subject it to the test of time.

The Commission does not agree, however, that the Utilities' ten year data set is the optimal choice for rate-setting. The Utilities' reasons for selecting that time frame ("rounding" and consistency with Nicor) do not make up for the greater predictive accuracy apparently associated with 8-, 12- and 11-year data sets. NS-PGL Ex. EST-1.0 at 32. Such "rounding" actually decreased predictive accuracy in this instance, by ignoring those superior data sets. Consistency with Nicor is not our principal objective at this point, since that case began, rather than ended, our movement away from reliance on thirty year data sets for ratemaking. As we noted in that proceeding, "Nicor did not study averaging periods other than ten years or thirty years to evaluate whether another period was even more appropriate." Nicor, at 53. Here, the Utilities demonstrated that other periods are "even more appropriate."

Consequently, we will choose between the two most accurate data sets (eight and twelve years). Utility witness Takle asserts that his own "regional climate model projects a trend in temperature since the mid-1990s that produces a trend in annual HDD totals which is very close to the trend calculated from recorded temperatures at O'Hare." NS-PGL Ex. EST-1.0 at 32. That tips the scale toward the twelve year interval, by aligning the predictive accuracy of that interval with Dr. Takle's perception of actual weather behavior at O'Hare over approximately twelve years. Moreover, while the Commission cannot know how long the rates established here will remain in effect, we do know that the Utilities' current rates have prevailed for twelve years. Therefore, the Commission approves weather normalization based on twelve years of data, which should determine the Utilities' HDD calculations incorporated in the rates resulting from these proceedings.

Additionally, we will require the Utilities to use the most recent twelve years, including 2007, to calculate HDDs for ratemaking purposes here. The Utilities have demonstrated that northern Illinois' climate is trending incrementally warmer. Consequently, the most relevant twelve year data will presumably be the most recent.

The Commission appreciates the concern of Staff, City-Cub and the AG that, without a standardized weather normalization period, utilities in future rate proceedings will offer customized HDD predictions, based on whatever data set produces the most revenue-friendly result. However, when we moved away from automatic reliance on thirty years of data in Nicor, our intention was to develop a better method for synchronizing allowed and actual revenues. Today, we continue that development, based on additional evidence. In subsequent rate cases, we will expect utilities to employ the principles and methods approved here or bear the burden of proving that additional measures will materially enhance the alignment of allowed and actual revenues.

Additionally, we note that our treatment of Rider VBA has diminished the importance of this issue.

VII. NEW RIDERS

A. Overview

North Shore and Peoples Gas have proposed five different new "tracker" riders: Riders VBA; WNA (as an alternative to VBA); ICR (Peoples Gas only); EEP; and, UBA. Each rider, they explain, presents an automatic adjustment mechanism for some factor affecting the revenues or expenses the Utilities experience. The Utilities further assert that each of the riders meets the traditional tests to be valid and useful riders.

1. Rider VBA

a) North Shore / Peoples Gas

A very large percentage of the Utilities costs are fixed. Even with the Utilities' proposed rate designs, they assert, a significant portion of fixed costs will be recovered through volumetric distribution charges. Rider VBA, the Utilities explain, is a rate mechanism designed to provide the Utilities with a measure of assurance of recovery of the portion of the revenue requirement approved by the Commission in these proceedings that is to be recovered through those volumetric charges. Rider VBA is commonly known as a decoupling mechanism. The purpose of decoupling is to remove both the incentive utilities have to increase sales and the disincentives that utilities have to encourage energy efficiency for their customers. The Utilities have proposed Rider VBA in this proceeding based on their recognition of current environmental and economic realities and the impact of those factors on the regulatory process and the utility business.

The Utilities explain that Rider VBA is a mechanism which will determine an adjustment on a monthly basis for the effects of weather and usage changes, such as those caused by conservation measures, on the Utilities' rates. Rider VBA will be applicable to the Utilities' customers under Service Classification ("S.C.") Nos. 1N, 1H and 2. A separate adjustment would be determined for each applicable service classification.

The Rider VBA adjustment would be computed on a monthly basis by taking the difference between a baseline rate case distribution margin per customer (Rate Case Margin) factor against actual distribution margin (Actual Margin) in a given month. The Rate Case Margin for each month would be based on the Commission approved distribution margin for each month divided by the number of Commission approved customers (Rate Case Customers) for the same month. The difference will be multiplied by the Rate Case Customers and divided by the number of therms estimated for the effective month of the adjustment, yielding the monthly per therm adjustment. The actual adjustment will be computed and applied to customers' bills each month using actual and rate case data from the second month prior to the effective month of the adjustment to be charged. PGL Ex. VG-1.0 2REV at 47; NS Ex. VG-1.0 3REV at 42-43.

A Base Customer Margin per customer and average number of customers level for each applicable rate classification will be established and a separate adjustment will be computed for each service classification. The monthly adjustments will be established by calculating the difference between the Base Customer Margin and the Actual Margin per customer for the applicable month. That difference will be multiplied by the Rate Case Customers and divided by the number of therms estimated for the effective month of the adjustment, yielding a monthly therm adjustment. Id. at 47 and 43, respectively.

According to the Utilities, Rider VBA would be subject to an annual reconciliation with adjustments to insure that the implementation of Rider VBA is in compliance with tariff provisions and would be filed on the 20th of the month to permit Staff review prior to the effective date of the adjustment. Annual internal audits would be conducted by the Utilities. PGL Ex. VG-1.0 2REV at 48; NS Ex. VG-1.0 3REV at 43; Staff Ex. 1.0 at 28.

b) Staff

Staff opposes Rider VBA on grounds that it violates several legal principles applicable to the development of rates; does not meet the legal burden necessary to warrant special rider treatment; adds additional regulatory overview to an already burdened system; and, unnecessarily supplements the Utilities earnings at the expense of the ratepayers, when the Utilities already have ample opportunity to achieve their authorized rate of return. For these reasons, Staff urges the Commission to reject Rider VBA.

Staff considers Rider VBA to be fundamentally different from any other rider which the Commission has authorized and the courts have upheld. Rather than provide for the recovery of a particular operating expense, Staff notes that Rider VBA seeks to guarantee revenue levels and earnings. According to Staff, Rider VBA takes the revenues that the rates approved in a base rate proceeding were intended to recover (which includes the Company's authorized return on rate base), and provides a surcharge if those rates produced insufficient revenues or a credit if those rates produced surplus revenues. In Staff's view, this is clearly contrary to the rule against retroactive ratemaking. It is well established, Staff argues, that the PUA "prohibits refunds when rates are too high and surcharges when rates are too low." Business & Professional People for the Public Interest v. Illinois Commerce Comm'n., 136 Ill. 2d 192, 209 (1989). Thus, once the Commission has determined a rate to be just and reasonable and put it into effect, it can not later determine the rate was excessive. Business & Professional People for Public Interest v. Illinois Commerce Comm'n., 171 Ill. App. 3d 948, 958 (1st Dist. 1988). Staff maintains that the Commission's authority to adopt formula-based rates does not include the power to provide for retroactive adjustments based on earnings. Illinois Bell Tel. Co. v. Illinois Commerce Comm'n., 203 Ill. App. 3d 424, 436 (2nd Dist. 1990).

Staff's view of Rider VBA is that it seeks to ensure recovery of 100% of the revenue requirement to be recovered through the volumetric component of rates irrespective of any actual reduction in demand. While the volumetric charges are designed to recover some costs that are fixed, these also recover variable costs. According to Ms. Grace, about 5% of Peoples Gas' costs and 1% of North Shore's costs vary with throughput. North Shore Ex. VG-1.0 REV at 6; Peoples Gas Ex. VG-1.0 2REV at 8. While these percentages are not high, Staff asserts that Rider VBA does not produce just and reasonable rates because it provides for recovery of costs that are not incurred if customers reduce demand.

According to Staff, Rider VBA also violates the prohibition against single-issue ratemaking. The rule against single-issue ratemaking, Staff explains, is based on the principle that the Commission sets rates based on aggregate costs and demands. As reasoned by the Supreme Court in Business & Professional People for the Public Interest v. Illinois Commerce Comm'n, 146 Ill. 2d 175, 244-45 (1991), the rule would be violated by consideration of changes in demand without considering changes in expenses, and vice versa.

Here, Staff argues, Rider VBA would adjust rates based on one component of the revenue requirement formula, i.e., revenue based on demand. Case law sustaining the approval of a rider against single-issue ratemaking challenges, Staff asserts, provides no cover to Rider VBA. In upholding the Commission's decision to permit rider recovery of coal tar clean-up costs in Citizens Util. Bd. v. Illinois Commerce Comm'n, 166 Ill. 2d 111 (1995), our Supreme Court held that "[t]he rule [against single-issue ratemaking] does not circumscribe the Commission's ability to approve direct recovery *of unique costs* through a rider when circumstances warrant such treatment." Id. at 137-138 (emphasis added). According to Staff, Rider VBA provides for the recovery of revenue rather than a particular operating expense, and thus does not fit within the exception recognized by the court.

While the Utilities posit that Rider VBA is needed to give them the proper incentives to implement energy efficiency measures, Staff points out that the Commission has not been given the authority under the PUA to adopt incentive based regulation, Illinois Bell Tel. Co. v. Illinois Commerce Comm'n., 203 Ill. App. 3d 424 (2nd Dist. 1990), and adopting a rider to provide for incentive based regulation is improper A. Finkl & Sons Co. v. Illinois Commerce Comm'n., 250 Ill. App. 3d 317 (1st Dist. 1993).

Staff also notes that in 1997, following the decisions in Bell and Finkl, the Illinois legislature passed into law Public Act 90-561, which rewrote Section 9-244 of the PUA to authorize the Commission to implement alternative incentive-based rate regulation in certain well defined circumstances. (See 220 ILCS 5/9-244) Staff notes that the Utilities have not asserted at any time in this proceeding that Rider VBA or Rider WNA are proposed pursuant to Section 9-244, and such riders do not fit within the specific authority provided therein for alternative incentive-based rate regulation. Moreover, Staff maintains that Bell and Finkl hold that the Commission lacks general authority to implement incentive-based regulation and may not rely on the provision of incentives to justify rider recovery continue to apply -- notwithstanding the specific incentive-based alternative rate regulation authorized by the amendment of Section 9-244 -- under the well established principle of statutory construction that "an amendatory act is to be interpreted as continuing in effect (as previously judicially construed) the unchanged portions thereof." (People v. Laboud, ,122 Ill. 2d 50, 55 (1988); see also Union Electric Co. v. Illinois Commerce Comm'n, 77 Ill. 2d 364, 380 (1979) ("It is well established that the reenactment of a statute which has been judicially construed is in effect an adoption of that construction by the legislature unless a contrary intent appears.")) Staff argues that Section 9-244 provides authority to implement alternative incentive-based rate regulation in specific limited circumstances, but nowhere indicates an intent to establish that the Commission has a general authority to implement incentive-based regulation.

All in all, Staff argues, Illinois courts have held a rider mechanism is effective and appropriate for cost recovery when a utility is faced with unexpected, volatile, and fluctuating expenses. Citizens Util. Bd. v. Illinois Commerce Comm'n., 166 Ill. 2d 111, 138-139 (1995). While the Utilities mention the "unexpected, volatile, and fluctuating" buzzwords in their support of Rider VBA, these are not in the context of an expense since Rider VBA seeks recovery of revenues and the everyday business challenges faced by a utility are not the type of special circumstances that justify rider recovery.

Turning to the record evidence, Staff does not necessarily believe the testimonial claim that the proposed rider will reduce the volatility of ratepayer bills. According to Staff, Rider VBA could actually increase the volatility of bills in that it adjusts margin revenues for an individual month, two months afterwards. PGL Ex. VG-1.0 at 47 and NS Ex. VG-1.0 at 42. For example, Staff notes that the under- or over-collection of margin revenues in December would be adjusted on February bills. If margin revenues in December fall below the target level, then February bills would be adjusted upwards to recover the shortfall. Staff notes, however, that if cold weather in February drives usage and customer bills above average, the February bill increase will be exacerbated by the upward Rider VBA adjustment to recover December's shortfall in margin revenues. In this instance, Staff argues, Rider VBA would exacerbate the upward spike in February customer bills. Staff Ex.8.0 at 12-13.

Staff considers Mr. Feingold's argument that reduced volatility would be accurate if margin revenues each winter are consistently above or below normal. Then, the adjustment process would bring monthly bills closer to the average. In Staff's view, however, a shorter-term variation in margin revenues could increase the volatility of ratepayer bills under Rider VBA as the above example shows. Id. at 13.

According to Staff, the Utilities have proposed other measures that Rider VBA does not take into account, which will also profoundly impact customer bills. At the outset, Staff notes, the Utilities propose to change from a 30-year to a 10-year weather normalization period. PGL Ex. LTB-1.0 at 10; NS Ex. LTB-1.0 at 14. This proposal, which Staff does not contest, should address the Utilities' concern that the decrease in gas delivered and sold to customers is in part due to a warming trend in weather. PGL Ex. RAF-1.0 at 17-19. Further, is the proposal to increase the levels of fixed, customer charges collected from ratepayers. If granted, Staff believes that increases in these charges would reduce the level of revenues recovered by variable charges and thereby stabilize the Utilities' revenue stream. And in Staff's view, both proposals, if accepted, will cause a reduction in revenue variability that undermines the Utilities' justification for an extraordinary measure, such as Rider VBA, to also stabilize revenues. Staff Ex. 8.0 at 13.

As to the argument that Rider VBA will restore incentive for Peoples Gas and North Shore to promote energy conservation and efficiency programs Staff does not agree. Usage data for the last 12 years indicates to Staff that ratepayers have already taken extraordinary steps to reduce their consumption. Utilities' witness Borgard documents a steep decline in natural gas throughput on the Peoples Gas system over recent years. He notes that throughput on the Peoples Gas system fell from the 1996 level of 235.7 Bcf projected in the Company's 1995 rate case down to a 2006 normalized level of 177.6 Bcf. According to Mr. Borgard, this represents a reduction of 58 Bcf or 25% over the 10-year period. PGL Ex. LTB-1.0 at 10. Mr. Borgard indicated that average annual use by residential heating customers declined by 29% from 160 to 113 dekatherms over the last decade (PGL Ex. LTB-1.0 at 16) and small residential heating customer use for North Shore declined by 16% from 159 to 133 dekatherms over the same 10-year period. NS Ex. LTB-1.0 at 14-15.

Staff also maintains that Mr. Feingold's reference to the "authorized level of margin revenues" for the Utilities is irrelevant in the current regulatory environment. According to Staff, margin revenue has no meaning as a standard for assessing the financial performance of Peoples Gas and North Shore in the Illinois regulatory process. The better and broader measure employed by the Commission concerns the rate of return achieved by the Utilities on their investments.

In Staff's view, simply because NARUC has acknowledged the function of revenue decoupling mechanisms does not translate into support for the adoption of these mechanisms by all state regulatory commissions. Indeed, as Mr. Feingold's own testimony states, NARUC's position is to encourage State Commissions "to review the rate designs they have previously approved to determine whether they should be reconsidered." Id. at 28 and NS at 25. Even if NARUC were to declare its support of revenue decoupling, Staff maintains that this would not mandate the Commission to act. Staff Ex.8.0 at 19-20. Further, Staff does not consider approval by regulators in ten states to demonstrate overwhelming regulatory support for revenue decoupling. Mr. Feingold's numbers would indicate that four out of five regulatory bodies have failed to adopt revenue decoupling. Staff Ex. 8.0 at 20. And, Staff notes too that, among the states that have approved such mechanisms, several have only approved pilot programs, or limited and modified revenue-decoupling programs. Several other states are acting under statutory direction to investigate revenue-decoupling mechanisms as an alternative to traditional statutorily approved ratemaking.

States that have approved decoupling mechanisms have done so with great apprehension, Staff points out, after thorough investigation and testing, and often at the behest of the legislature. These states have adopted revenue decoupling mechanisms, but either as pilot program, with safeguards, or both. In contrast, the instant Rider VBA does not have, nor have the Utilities proposed, any safeguards to protect the ratepayers. The instant Rider also does not allow the Commission to review the effectiveness of the Rider before the Utilities choose to file for another rate case, and there is no expiration or test period to evaluate the effects of Rider VBA.

In Staff's view too, Rider VBA is being proposed to address a problem that does not exist. The financial distress the Utilities claim has simply not been established. The available evidence indicates that Peoples Gas and North Shore have achieved sustained success in recent years despite the business challenges. For example, as Company witness Feingold acknowledges, the cost of service consists of two components, expenses and a rate of return on rate base. Tr.1350. Therefore, if after paying its expenses, the utility realizes its approved rate of return, then the utility is, by definition, recovering its cost of service. According to Staff, Peoples Gas and North Shore have consistently met or exceeded their approved rates of return and recovered the cost of service for a full decade after their last rate case in 1995.

Staff maintains that proposed Rider VBA suffers from numerous deficiencies and asks that it be rejected by the Commission in this proceeding. In the event that the Commission were to determine it appropriate for the Utilities to adjust base rates on a monthly basis for fluctuations in actual revenues, Staff recommends the Commission adopt the language changes which are reflected in legislative style in Attachment C, Staff Revised VBA, to Staff Exhibit 1.0.

The changes are: 1) to reflect an annual reconciliation with possible adjustments to ensure the VBA is in compliance with the tariff; 2) to change the monthly filing date to allow for Staff review prior to the effective date; and 3) to require the Utilities to perform annual internal audits on compliance of the UBA. Staff points out that the Utilities stated no opposition to these proposals, other than one change in the definition of RA. NS-PGL Ex. VG-2.0 at 50. And Staff had no opposition to the Utilities rebuttal changes. Staff Exhibit 13.0 at 15.

c) City - CUB

In assessing Rider VBA, City-CUB point out, the Commission must first determine whether the costs at issue meet the criteria for rider recovery. Only then, they argue, is it able to decide whether or not to exercise its discretionary authority to permit rider recovery. Here, City-CUB assert, the Utilities cannot claim that Rider VBA is designed to recover a volatile, fluctuating cost that is beyond their control. This is so, they argue, because Rider VBA is designed to protect utility revenues and earnings and not to recover a particular cost. And, because the rider at hand would adjust utility revenues outside of a rate case by, in effect, increasing rates when revenues are too low and decreasing rates when revenues are too high, City-CUB maintain that Rider VBA would violate the rule against retroactive ratemaking. <u>Business & Professional People for the Pub. Interest v. Illinois Commerce Comm'n.</u>, 136 Ill. 2d 192, 209 (1989) ("<u>*BPI I*</u>").

City-CUB observe nothing in the record to show that the Utilities' respective revenues have been volatile and fluctuating. Their witness Brosch included in his rebuttal testimony two tables showing the margin revenues for Peoples Gas and North Shore from 1996 through 2006. GCI Ex. 4.0 at 6, 7. The table relating to Peoples Gas's margin revenues (Table 6) shows that PGL's margin revenues have hovered around $400,000,000 per year for Peoples Gas over the entire 11-year period exhibited. <u>Id</u>. at 6. North Shore's margin revenues, as demonstrated in Table 7, have stayed around the $60,000,000 level for the same period. Even if one could lawfully protect utility revenues and earnings through use of a rider, City-CUB maintain that the evidence indicates the Utilities' respective revenues have not been volatile or fluctuating, as Illinois case law requires for rider recovery of specific costs. Thus, City-CUB argue, approving Rider VBA would violate the rule against single-issue ratemaking.

City-CUB also observe the Utilities to claim that Rider VBA should be approved because it does not shift any risk to ratepayers. *See* PGL-NS Init. Br. at 116. The evidence in the case, City-CUB argue, well contradicts that point. Staff witness Lazare's testimony, they note, references the Utilities' answer to an AG data request asking what revenue changes would have been experienced in the past five years if Rider VBA had been in place. The results indicated therein show that Rider VBA would have been a boon to the Utilities. Staff Ex. 8.0 at 7. These numbers, City-CUB note, total to an additional $218 million in pre-tax operating income for Peoples Gas and an additional $24 million in pre-tax operating income for North Shore. GCI Ex. 1.0 at 37. According to Mr. Brosch testimony, and based on the Utilities' analysis of the rider's impact had Rider VBA been in effect for the past five years, Peoples Gas's margin revenues would have increased by about 11.2% and North Shore's margin revenues would have increased by 8.9%. Id. at 37. Contrary to the Utilities' claim, City-CUB argue, these results suggest that considerable risk would be shifted to customers if Rider VBA were approved.

d) The AG

The AG also opposes Rider VBA and on several grounds. At the start, the AG points out that the *Finkl* Court held that rider recovery constitutes extraordinary regulatory treatment that should be used only when evidence exists to show that traditional ratemaking will not effectively reflect the costs in rates. In order to qualify for rider recovery, the AG observes, such expenses must be unexpected, volatile or fluctuating and significant in nature.

GCI witness Brosch testified that while the proposed Rider VBA can be expected to produce relatively large cumulative revenue impacts if it remains in place for many years between rate cases, the change in revenues in individual years is not particularly large. According to the analysis provided by the Company, which detailed the revenue effects if Rider VBA had been in place beginning in 2002, the largest annual margin dollar change was $21.7 million for PGL and $4.5 million for North Shore in 2003. GCI Ex. MLB-1.0 at 39-40. These amounts, after reduction to account for income and revenue taxes of about 40 percent, are significant in the AG's view, but not particularly large in relation to the total test year operating income proposed by PGL of $108 million at proposed rate levels and $16.9 million for North Shore at proposed rate levels. Id*.* at 40. On this criterion alone, the AG asserts, rider treatment is not justified.

In terms of the volatility criterion, the AG notes, Rider VBA fails the test. It was demonstrated in Brosch's testimony that the actual recorded PGL annual margin revenues have been stable in overall terms for the past 11 years, and fluctuations due to weather and other causes were within or less than 8 percent of the average amount. *See* GCI Ex. 1.0 at 32, 33; GCI Ex. 4.0 at 6, 7. Similarly, for North Shore, relative margin revenue stability is evident across the 1996 through 2006 time period, indicating no apparent financial need for Rider VBA tracking of usage per customer. GCI Ex. 4.0 at 33. Mr. Brosch also pointed out that the magnitude of changes in annual VBA adjustment amounts, as shown in GCI Ex. MLB-1.3, does not effectively eliminate margin fluctuations during the years modeled. *See* GCI Ex. MLB-1.3 and GCI Ex. MLB-1.0 at 38, 39; Tables 4 and 5.

As such, the AG argues, the usage or revenue per customer decline that Rider VBA is intended to address does not satisfy the "unexpected" criterion referenced in the Finkl case. As both Mr. Feingold and Mr. Borgard have acknowledged, declining use per customer has been a phenomenon occurring for decades. Tr. 378; 1321-1322. Despite this phenomenon, the Utilities have not sought rate relief since 1995 and thus, were able to react to this observable trend through productivity improvement, customer growth, expense reductions and a decrease in the Utilities overall cost of capital. *See, e.g.*, PGL Ex. LTB-1.0 at 13-15. According to the AG, nothing of record suggests that declines in usage per customer, and thereby revenues per customer, will produce unacceptable financial outcomes if the Utilities are not allowed special rider treatment.

The AG points to GCI witness Brosch's testimony which observes that the Rider VBA proposal ignores the traditional ratemaking process, which employs a balanced review of jurisdictional expenses, rate base investment, the cost of capital and revenues at present rates during the test year. If enacted, the AG argues, Rider VBA would violate the Act's prohibition against single-issue ratemaking by imposing a surcharge each month on customers' bills if overall usage in three rate classes dipped below the aforementioned baseline level set in this case, without examining whether *overall* revenues have increased. *See* PGL Ex. RAF 1.0 at 32. Similarly, it would impose a surcharge even if an observable cost reduction in a certain expense category was available to offset any future decline in revenues per customer.

The AG contends that traditional rate of return regulation has worked well for both the Utilities and consumers. Further, the AG notes, rates for Peoples and North Shore will be recalibrated at the conclusion of this docket based on record evidence regarding their respective revenue requirements. If the declining usage per customer trend that has existed since the 1980s affects the Utilities' earnings in the future to a point that rate relief is deemed necessary, the AG observes that the Utilities are free to file a rate case.

The AG notes that the Finkl case specifically rejected the notion of requiring ratepayers to reimburse a utility for revenues lost due to energy efficiency and conservation measures. In Finkl, the AG explains, the Rider 22 at issue would have authorized Edison to charge ratepayers for lost revenues associated with demand-side management activities, similar to the Utilities' request in this docket to adjust rates each month when margin revenues fall below a revenue per customer baseline established in this Order. The Finkl court noted that the proposed Rider 22 recovery of lost revenues associated with the DSM programs "fails to take into consideration Edison's aggregate costs and revenues, which is also the vice inherent in this revenue recapture." Finkl at 328. And, the Court flatly rejected the notion of making a utility whole for lost revenues associated with conservation or DSM programs. Given the *Finkl* court's specific rejection of ratepayers compensating a utility for lost revenues arising from energy efficiency and other measures, the AG argues that the Commission should reject the Rider VBA proposal.

Given the absence of specific statutory authority authorizing the adjustment of customer rates, both on a monthly, piecemeal basis and in the proposed annual reconciliation of Rider VBA revenues, as well as the rule prohibiting retroactive ratemaking, the AG believes it clear that the Commission lacks the authority to approve Rider VBA.

In addition, the AG contends that proposed Rider VBA violates the Commission's and Illinois law's test-year principles by selecting only one component of the revenue requirement, in this case a slice of overall revenues (margin revenues per customer in the Rate 1 and 2 classes), then tracking changes in that revenue requirement component and assessing rate adjustments to recognize this change. Such an approach, the AG argues, would distort test year matching by continuously revising utility prices for changes in future usage per customer, even though other elements of the test year revenue requirement calculation are not being systematically updated.

The AG further points out that Section 9-241 of the Act prohibits a utility from establishing or maintaining any unreasonable difference as to rates or other charges between customer classes. 220 ILCS 5/ 9-241. Here, the AG observes that Peoples and North Shore seek to maintain a designated level of revenues per customer on a monthly basis after rates are set in this docket for the Rate 1 residential and Rate 2 commercial classes, but not for the other rate classes served by the Utilities. Nowhere, the AG notes, is there any evidence to show that the weather variability, declining use per customer, or conservation phenomena are at all unique to residential and small commercial customers and should not also be applicable to larger gas consumers. There is no showing, for example, that Large Volume Demand Service customers' usage, and therefore some element of their fixed cost contribution, are not also impacted by the reductions in usage associated with weather and conservation efforts. Nevertheless, the AG notes, Rider VBA and its monthly rate adjustments arising from variations in usage per customer baseline calculation, would not apply to this customer class. As such, the AG argues, Rider VBA constitutes unreasonable discrimination against residential and small commercial customers.

The AG maintains that state and federal regulatory law is not premised on the concept of maintaining a utility's "margin revenues". The seminal federal cases in utility regulation, the AG asserts, make clear that a utility is entitled to the opportunity to earn a reasonable return of, and on, its prudently incurred utility plant. No mention is made of an inherent right to maintain some level of "margin revenues" or "use per customer". GCI witness Brosch also disagreed with the notion that a specific margin revenue should be guaranteed. He expressly noted, the AG points out, that all of the ratemaking input values will change in the future; test year expenses will change, the cost of capital will change and test year rate base values are not expected to remain constant after completing a rate case. GCI Ex. MLB-1.0 at 36. Even if the Utilities could make a case for the need to ensure its margin revenues, the AG observes that proposed Rider VBA can assess a surcharge even if total revenues increase above the level approved in this rate case, if the use *per customer* declines. According to the AG, there is nothing in the

Act or in Illinois case law setting out a utility's right to maintain a specified level of revenues or usage per customer.

Absent from the record too, the AG notes, is any evidence that *overall* margin revenues have dropped precipitously or become unstable in the years since the Utilities' last rate case so as to justify the unorthodox ratemaking treatment that Rider VBA brings. Despite the declines in usage per customer detailed by Messrs. Borgard and Feingold, the AG observes that overall margin revenues for both Utilities have been remarkably stable. As such, the AG argues, there is simply no basis for the extraordinary ratemaking treatment inherent in Rider VBA.

More specifically, the AG notes that the Utilities presented no evidence to show that they will be precluded from earning reasonable returns in the future absent the newly proposed Rider VBA. When asked in discovery to provide projections of future financial performance with or without the riders, the Utilities responded that, "There are none." GCI Ex. 1.0 at 20. As importantly, the AG notes Mr. Borgard to have confirmed that the Utilities *can* continue to provide safe, adequate and reliable service to all customers *without* Rider VBA. Tr. 392.

According to the AG, the argument that a decoupling rider is needed to remove any disincentive the Utilities might have to promote energy efficiency, PGL Ex. RAF-1.0 at 22; NS Ex. RAF-1.0 at 24, should be rejected for several reasons. First, the AG maintains that Peoples' and North Shore's participation in energy efficiency programs to date have been minimal and primarily the result of legal settlement. Outside of an agreement to contribute $5 million to energy efficiency measures arising out of a settlement in the Docket No. 01-0707 Peoples/North Shore PGA case, and a separate agreement in the recent merger settlement to spend a combined Peoples/North Shore maximum of $7.5 million on an energy efficiency program to be administered by a third party governance board[29], neither Company has any history of promoting or designing significant energy efficiency programs for its residential customers. Second, the AG notes that the Utilities' witness Borgard, made clear during cross-examination that there are no plans to grow energy efficiency programs beyond the $7.5 million program being proposed in this docket either with or without Rider VBA. Tr. 390. Third, the AG observes that the program that the Utilities proposed (with the support of the People and the Environmental Law and Policy Center), would be administered by a third-party Governance Board, which would have control over program selection and marketing. While the Utilities would have a representative among the five-person Board, it is fair to say that they would not be in control of marketing or promotional decisions. Finally, the AG suggests that Rider VBA would, in effect, punish Peoples and North Shore customers by raising future per therm charges on a monthly basis when customers conserve and reduce future gas usage and margin revenue-per-customer below the threshold level set in this docket. It would cause customer confusion given the contradictory price signals sent by adjusting per therm charges upward when usage per customer decreases and likely diminish the incentive customers have to lower their

[29] Docket 06-0540, Memorandum of Agreement at 3, 4.

thermostats, invest in more energy efficient appliances and weatherization measures, or even participate in the company-sponsored programs. GCI Ex. 1.0 at 44.

The AG is similarly not impressed with the Utilities' claims on the nationwide trend toward approval of decoupling mechanisms. At the outset, the AG observes that in Mr. Feingold's discussion of states that had approved a decoupling rider, these involved, in each instance, approval *by settlement* between the utility, a PSC staff and intervening parties, with a quid pro quo of specific commitments toward conservation and energy efficiency programs. Tr. 1286, 1288, 1289, 1291-1296; *Compare* PGL Ex. RAF-2.0 45-46, In the Matter of Northwest Natural Gas – Investigation Regarding Possible Continuation of Distribution Margin Normalization Tariff*,* Order, August 25, 2005. Further, the AG notes that there is wholly absent from Mr. Feingold's testimony any discussion of state commission decisions that had rejected decoupling proposals similar to the Rider VBA proposal in this proceeding. Accordingly, the AG asserts that Mr. Feingold's testimony on the other jurisdictional approvals is of little value.

Considering the Utilities' claim that Chicago-area weather has been and will be warmer than in years past and that historical declines in natural gas usage per residential customer will continue in the future, the AG believes that the approval of Rider VBA will only deliver generally higher prices and a significant shifting of risk for Peoples' and North Shore's customers, with no benefits in return. For example, the AG notes, the Utilities' witnesses to have made clear that no commitment to refrain from filing a rate case in the future will accompany approval of its rider proposals. Tr. 1541. Similarly, the Utilities specifically rejected the notion that their authorized return on equity should be lowered in recognition of this transfer of risk from the Utilities to its customers. PGL-NS Ex. PRM-2.0. In sum, the AG argues, the record evidence supports Commission rejection of the proposal.

The AG contends that still another reason to reject Rider VBA is that riders, in general, add complexity to regulatory processes in a myriad of ways. This concern was testified to by both GCI witness Brosch and Staff witness Lazare and at length. Further, the AG observes that the inherent complexity in the monthly filings and calculations that are being proposed to administer Rider VBA, can be seen in the proposed Rider VBA tariff itself. *See* PGL Ex. VG-1.16; NS Ex. VG-1.15. According to the AG, The cumulative burden that the review of Rider VBA would add to the Commission Staff's and the consumer intervenor parties' respective auditing and advocacy responsibilities is another reason to reject the Company's Rider VBA proposal.

e) North Shore / Peoples Gas' Response

The Utilities note certain parties to have made generalized arguments claiming that the Utilities' actions have no bearing on customer conservation decisions. But, the Utilities maintain that the existence of the "Throughput Incentive" cannot be denied. According to the Utilities, the Throughput Incentive encourages a utility such as Peoples Gas or North Shore to be financially motivated to increase sales of natural gas (relative to historical levels which underlie base rates) and to maximize the "throughput" of natural gas across its utility system.

Under the traditional utility ratemaking structure, Peoples Gas and North Shore point out, a utility is financially motivated to increase its sales levels in a future period above that established in its previous rate case because its rates are designed to recover most fixed costs on a volumetric basis – causing the utility's revenues to increase as its sales increase. Under traditional utility ratemaking, an increase in the recovery of fixed costs will occur (compared to the level approved in the utility's most recently completed rate case) when sales are higher than assumed in the design of the utility's rates. Conversely, a decrease in the recovery of fixed costs will occur when sales are low relative to assumed levels. This situation, the Utilities assert, creates an automatic disincentive for utilities to promote conservation or energy efficiency initiatives because such actions will reduce the utility's revenues and resulting earnings.

The Utilities would compute a monthly adjustment under proposed Rider VBA to offset the revenue impact of increases or decreases in sales. By doing so, they explain, proposed Rider VBA would effectively eliminate the link between sales and earnings. Hence, Rider VBA would encourage the Utilities to be supportive of measures which would promote decreased energy usage, conservation, or other energy efficiency initiatives. Feingold Dir., PGL Ex. RAF-1.0. The only other arguments which have been set out in opposition to Rider VBA are that it departs from "traditional ratemaking" and would introduce a measure of complexity and administrative burden for regulators. Such arguments are meritless, the Utilities argue.

It cannot be disputed, the Utilities assert, that more and more state commissions are approving revenue decoupling mechanisms similar to Rider VBA in recognition that such mechanisms have identifiable benefits for ratepayers and utilities. The state of New York, the Utilities observe, has even seen fit to recommend that all utilities in the state propose decoupling measures to address today's business realities. Re Investigation of Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, et al., 256 P.U.R. 4th 477, 2007 WL 1185703 (N.Y.P.S.C. Apr. 20th, 2007) (Docket No. 03-E-0604).

Rider VBA is an opportunity for the Commission to participate in this growing acknowledgement of the need for rate setting bodies to address issues of global warming impacts and energy independence and their impact on energy utilization, conservation and utility financial stability. Rider VBA, the Utilities assert, serves these critical goals by providing them with a measure of financial stability that will enable them to participate enthusiastically in promoting energy conservation and efficiency without the fear of undermining their business interests.

The Utilities point out that decoupling mechanisms, and their rate tracking features have been widely adopted by state regulatory commissions over the past several years. Decoupling mechanisms had been adopted in at least 9 states when the Utilities filed their cases and that number had risen to 11 nearly six months later with 14 additional states considering decoupling in some manner. NS-PGL Ex. RAF-3.0 at 5. Decoupling mechanisms are becoming increasingly more common across the country in response to significant environmental and national interest considerations, as well as the business challenges faced by natural gas utilities. The environmental challenges that Rider VBA would address, the Utilities explain, involve issues of global climate change and the real need for the nation to become more self sufficient in energy. NS-PGL Init. Br. at 110-111. Exhibit NS-PGL RAF-2.3 shows the increasingly widespread adoption of decoupling mechanisms across the U.S. While no decoupling mechanisms have been adopted in Illinois, the policy challenges and business justification which are the predicate for decoupling mechanisms certainly do exist in this state.

Among these new realities is that utilities can no longer expect that increased sales are a viable business goal in the face of declining use and the rising cost of natural gas. Moreover, current concerns over global warming and dependence on energy imports have prompted utilities and other policy makers to reevaluate existing regulatory models and express support for decoupling. This has resulted in an ever increasing number of utility proposals and regulatory decisions to implement decoupling and similar type rate policies.

The Utilities point to numerous decisions of other state commissions approving decoupling, and urge the Commission here to make a similar decision. While some decoupling mechanisms have not been approved, the Utilities believe that there is movement toward broader approval. Further the Utilities' financial under-performance in the recent past is clearly indicative of acute business challenges that give rise to the need for new ratemaking approaches because traditional ratemaking approaches do not address current business and environmental realities. A utility's financial results and the environmental consequences of certain ratemaking practices cannot be ignored or downplayed simply to preserve the *status quo*.

Furthermore, the Utilities argue, Rider VBA will not entail any shift of risk to customers because it does not guarantee any specific financial performance. To the extent normal weather is assumed over time, Rider VBA's adjustment to reflect weather represents no risk shifting. Similarly, risks attendant to throughput are evened out by the upward and downward adjustments for warmer and colder weather, respectively. There is no adjustment if the Utilities add or lose customers relative to the customer levels established in these proceedings. The adjustment for usage is symmetrical, i.e., both declines and increases are taken into account. NS-PGL Ex. RF-2.0 at 50-51.

On Exceptions the Utilities note that "The Commission is free to make such 'pragmatic adjustments' as it deems appropriate." NS-PGL BOE at 50. The Utilities further note that these adjustments "could include conditions that Rider VBA may only be implemented as a pilot mechanism, or that Rider VBA be subject to a time frame within which it may remain effective or be subject to the Utilities' being required to file a new rate case to justify its continuation beyond a definitive time frame." Id.

f) Commission Analysis and Conclusion

This case presents the Commission with its first introduction to decoupling mechanisms and it is being presented here with proposed Rider VBA. In simplest form, Rider VBA would adjust customer prices under Service Classifications Nos. 1 and 2, and in a way that the Utilities revenues are held constant despite changes in customer consumption. Such changes in consumption are brought about by rising natural gas prices, the call for conservation measures, warming weather trends, the involvement of the Utilities in gas efficiency programs, and other events. The proposed monthly adjustments under Rider VBA are symmetrical meaning that they are based on both the over-recovery as well as the under-recovery of target revenues. Implementing Rider VBA imposes some additional administrative expenses and, among other things called for by Staff, there would be annual internal audits.

The question raised by Staff and the GCI parties is whether Rider VBA is legal, i.e., whether it is the type of mechanism that the Commission has authority to adopt. We note Staff to assert, that Rider VBA is fundamentally different from any other rider that the Commission has authorized thus far and which the courts have approved. For their part, the GCI contend that there are serious legal obstacles to be considered. Against these claims, we assess, from the very beginning, the scope of our authority in the matter of riders.

1. Rider Authority

In City of Chicago v. Illinois Commerce Comm'n, 13 Ill. 2d 607 (1958) ("City I"), we observe, the Illinois Supreme Court considered the Commission's power to approve an automatic adjustment clause to be filed in a rate schedule. This opinion makes clear that the Commission's authority to approve rate schedules "embraces more than the authority to approve rates fixed in terms of dollars and cents." Id. at 611. It also includes the power to adopt a set formula to recover costs in appropriate circumstances. Id. In sum, our Supreme Court declared that the legislature has vested in the Commission the ratemaking function which includes the making of "pragmatic adjustments." Id. at 618.

Over the years, we find that the Illinois courts have reviewed the rider mechanism in a number of different circumstances. See A. Finkl v. Illinois Commerce Comm'n, 250 Ill. App. 3d 317 (1st. Dist. 1993) ("Finkl") reversing a rider order for recovery of a type of ordinary costs that should have been included in rate base; City of Chicago v. Illinois Commerce Comm'n, 264 Ill. App. 3d 403 (1st Dist. 1993) ("City II") affirming a Commission order that approved with modification, a rider for recovery of marginal cost of providing non-standard service; Central Illinois Light Co. v. Illinois Commerce Comm'n, 255 Ill. App. 3d 876 (3rd Dist. 1993) ("CILCO") finding no abuse of discretion in the Commission's ordering of coal tar remediation cost recovery through a rider mechanism; Citizens Utility Board v. Illinois Commerce Comm'n, 166 Ill. 2d 111 (1995) ("CUB v. ICC"), affirming on that issue against further rider challenges; City of Chicago v. Illinois Commerce Comm'n, 281 Ill. App. 3d 617 (1st Dist. 1996) ("City III"), upholding the Commission's order for rider recovery of the utility's franchise costs; Illinois Power Co. v Illinois Commerce Comm'n, 339 Ill. App. 3d 425 (5th Dist. 2003) recognizing that the Commission sets rates in two ways-by base rates or by an automatic-cost-recovery mechanism.

Throughout, all that was established in City I remains good and sound law. Indeed, we observe, 37 years after it set out the seminal pronouncements in this field, the Illinois Supreme Court highlighted City I to affirm the Commission's discretion in selecting the means by which rates are set and costs are recovered, and the appropriateness of the rider mechanism in certain instances. CUB v. ICC, 166 Ill. 2d 111 (1995). Thus, the whole of the case law settles the question of our authority to adopt the rider mechanism in proper situations and under circumstances that are lawful and reasonable.

2. The Legal Objections to Rider VBA

Claiming that the instant Rider VBA is outside the Commission's authority, Staff and the GCI maintain that this mechanism violates certain well-established regulatory doctrines. These, they claim, are single issue ratemaking, retroactive ratemaking, and the Commission's own test year rules.

To be sure, both the GCI and Staff also contend that Rider VBA is unlike any other rider that has been considered by any court. But, Staff further acknowledges that, the lack of judicial review on a rate adjustment such as Rider VBA does not mean that it cannot be judged against the standards that our Illinois courts have considered. We agree with this proposition. Continuing with our analysis, we observe that the Illinois courts have defined, discussed and addressed the legal principles at hand, and their application, in a number of different situations.

While Staff and the GCI parties' briefs and exceptions highlight limited aspects of the relevant case law, we find it necessary to take a more thorough approach in analyzing these court opinions and discerning the guidance that they offer in this matter.

a. Single Issue Ratemaking

In the GCI's view, Rider VBA would inappropriately adjust rates on a going-forward basis to ensure a designated level of revenues per customer, without examining whether overall revenues have increased or whether expenses have decreased to offset revenue losses. This, they contend, violates the prohibition against single-issue ratemaking.

We take a studied look at this regulatory principle and its application by the courts. At the outset, we observe that on review of a rate case proceeding in <u>Business and Prof'l People for the Pub. Interest v. Illinois Commerce Comm'n</u>, 146 Ill. 2d 175 (1991) ("BPI"), the Illinois Supreme Court explained that the rule against single-issue ratemaking recognizes that the revenue formula [R(revenue requirement) = C(operating costs) + Ir (invested capital or rate base times rate of return on capital)] is designed to determine the revenue requirement based on the aggregate costs and demand of the utility. Thus, the Court observed, it would be improper to consider changes to components of the revenue requirement in isolation for oftentimes a change in one item of the revenue formula is offset by a corresponding change in another component of the formula. <u>Id</u>. at 244-245.

This pronouncement figured prominently in the opinion of <u>A. Finkl & Sons Co. v. Illinois Commerce Comm'n</u>, 250 Ill. App. 3d 317 (1st Dist. 1993) ("Finkl"), where the court considered a stand-alone Commission order that allowed Commonwealth Edison Company ("Edison") to recover costs associated with demand-side management ("DSM") programs through a rider and outside a rate case proceeding. The court reviewed the elements of the traditional ratemaking process and determined that, in this instance, the expenses incurred with least-cost planning, i.e., are ordinary expenses of the type recoverable through the usual base rate mechanism. Under this view, the court considered that the Commission had improperly authorized Edison to charge customers for DSM program costs without considering whether other factors offset the need for additional charges in violation of the prohibition against single-issue ratemaking. According to the court, Edison's failure to include such costs "in its request for a rate increase" did not justify single-issue treatment of costs in a rider. Id. at 327.

In CILCO, however, the court found no abuse of discretion where the Commission's order concluded that coal tar mediation costs would be recovered through the rider mechanism. The challenging parties had relied on Finkl to argue that riders, in general, violate the prohibition against single issue and retroactive ratemaking, and the Commission's "test year rules." The court rejected such a broad reading of Finkl and limited its holdings to the particular facts of the case by stating that:

> In Finkl, the First District….found the demand-side management expenses were not of such a nature as to require rider treatment, and could be readily addressed through traditional base rate proceedings. Id. at 885.

In terms of the matter before it, the CILCO court noted that the costs for rider recovery will vary from year to year such that the Commission had authority to authorize a rider as a preferred means of recovery. Id.

The matter was taken for higher review and, in CUB v. ICC, the Illinois Supreme Court boldly announced that the principle of single-issue ratemaking (as set out in BPI) does not apply except in the context of a complete base rate proceeding. 166 Ill. 2d at 138. The Court observed that this was not a situation where the Commission was treating a single expense item within the context of a general rate case. Even more pointedly, the Illinois Supreme Court set out that:

> [A] rider mechanism merely facilitates direct recovery of a particular cost, without direct impact on the utility's rate of return. The prohibition against single-issue ratemaking requires that, in a general base rate proceeding, the Commission must examine all elements of the revenue requirement formula to determine the interaction and overall impact any change will have on the utility's revenue requirement, including its return on investment. The rule does not circumscribe the Commission's ability to approve direct recovery of unique costs through a rider when circumstances warrant such treatment. CUB v. ICC, at 138 (emphasis added).

Further, in City III, the court upheld the Commission's approval of a separate line-item charge that had franchise fees being charged to the residents of the municipalities assessing the fees, while also removing them from base rates for all customers. The court disagreed that the use of a rider for recovery of these costs violated the rule against single-issue ratemaking, and cited favorably to the Illinois Supreme Court's pronouncement that: "The rule (against single-issue ratemaking) does not circumscribe the Commission's ability to approve direct recovery of unique costs through a rider when circumstances warrant such treatment." Id. The court further observed that, in the situation at hand, the reallocation that the Commission ordered had no impact on Edison's overall revenue requirement. Where the franchise fees were already included in Edison's overall rate structure, the court reasoned that the Commission simply distributed them with no "direct impact on the utility's rate of return." City III, 281 Ill. App. 3d at 629.

Finally, in Archer-Daniels-Midland Co. v. Illinois Commerce Comm'n, 184 Ill. 2d 391 (1998) ("Archer-Daniels"), we observe that the Illinois Supreme Court upheld a Commission order that allowed the recovery of contract restructuring costs as costs of fuel under a UFAC rider. Specifically, the Court held that the lower court erred in finding the rule against single-issue ratemaking to have been violated. The Court reiterated its holding that, this rule does not apply "except in the context of a complete base rate proceeding" such that it "does not apply in relation to the use of a rider mechanism." Id. at 401-402. Given that the proceeding at hand was not a complete base rate proceeding, the Court found that "the rule against single-issue ratemaking has no application." Id.

Analysis:

From the whole of this authority, we believe it clearly established that the prohibition against single issue ratemaking is operable only in the context of a rate case, and during the phase that balances the utility's cost and allowed revenues under the R=C+Ir formula. It is not applicable to a rider that merely facilitates direct recovery of a particular cost without upsetting a utility's revenue requirement.

Consistent with the pronouncements in CUB v. ICC, City III, and Archer-Daniels, the margin revenues which are recovered under Rider VBA do not involve single issue ratemaking because they do not have any impact whatsoever on the Utilities' overall revenue requirements. *See* City III, 281 Ill. App. 3d at 629. Simply put, margin revenues will have been determined as part of the overall revenue requirement in the instant proceeding and the adjustments that occur under Rider VBA will do nothing to change the Utilities' approved revenue requirement. As such, and under the law, Rider VBA does not violate the rule against single issue ratemaking and we reject the arguments of Staff and GCI to the contrary.

b. Prohibition Against Retroactive Ratemaking.

GCI contends that Rider VBA violates the prohibition against retroactive ratemaking by permitting monthly and annual rate adjustments after rates are established in this case. As such, they argue, Rider VBA would adjust future residential (Rate 1) and general service (Rate 2) customer bills on a monthly basis, using comparisons of actual vs. prior rate case data applying formulistic rate changes determined under the rider. For example, they note, the Rider VBA amount to be computed based on October results would be applied to customer bills in December.

In addition, the GCI observe, Rider VBA's tariff provisions require annual true-ups, with any resulting adjustment (positive or negative) added to or deducted from customers' bills during that period. They observe Utilities witness Grace to have testified that, "any difference between actual billed revenues arising from distribution charges plus the adjustment and approved distribution margin under the rider will be reconciled on an annual basis and amortized over a 10-month period beginning March, with any resulting positive or negative adjustment added to customers' bills during that period." PGL Ex. VG-1.0 at 47; NS Ex. VG-1.0 at 43. Noting that reconciliations are permissible and do not constitute illegal retroactive ratemaking for expenses appropriately recovered under a rider (such as in Purchased Gas Adjustment Clause proceedings or environmental remediation dockets), the GCI argue that reconciliations on both a monthly and annual basis to capture revenue changes are not permitted under the Act or any Illinois case law analyzing rider recovery.

We here examine what the doctrine at hand really holds and what it means for Rider VBA. It is well established, we find, that the prohibition of retroactive ratemaking is derived from the overall scheme of the PUA and the legislative role assumed by the Commission in the ratemaking process that is prospective by nature. Citizens Utilities Co. v. Illinois Commerce Comm'n, 124 Ill. 2d 195, 207 (1988) ("Citizens Utilities"). This means that once the Commission sets rates, the Act does not permit refunds if the established rates are too high. Nor does it allow for surcharges if the rates are too low. Id. Clear from its initial announcement in the opinion of Mandel Brothers, Inc. v. Chicago Tunnel Terminal Co., 2 Ill. 2d 205 (1954) ("Mandel Brothers"), it is the integrity and stability of the ratemaking process that the rule aims to protect. Another important aspect of the rule, is that the PUA forbids a utility to charge rates different than those established by the Commission in its legislative capacity. Id. at 210.

It has evolved that the sanctity and conclusiveness of the ratemaking process also bears upon the Commission itself. This concept was well illustrated in Citizens Utilities where a Commission rate case order included a $4.2 million reduction to rate base on grounds that a higher tax figure had been used to establish the utility's rates in past years. In addressing the challenges to that action, the Illinois Supreme Court observed that the tax benefits at issue originated as expenses the utility previously had been allowed to recover, meaning that:

> Just as there is no recovery of reparations for rates charged under a Commission order later held to be invalid (Mandel Bros.) there can be no retroactive adjustment simply because the Commission has now decided to treat tax benefits differently. Citizens Utilites,124 Ill.2d at 211.

To be sure, the court in Finkl agreed with the argument that Rider 22 violated the prohibition against retroactive ratemaking. 250 Ill. App. 3d at 329. But, we observe, nothing in the Finkl opinion provides an explanation of the court's reasoning. There is only mention that Rider 22 provided for a prudency review of the expenses passed on to customers with the possibility of refunds if the rates were too high. And, the court summarily cited to BPI v. ICC, 136 Ill. 2d 192 (1989), for the proposition that "[o]rdering of refunds when rates are too high, and surcharges when rates are too low, violates the rule against retroactive ratemaking." Id.

We observe that, in CILCO, parties relied on Finkl in arguing that the riders in general violate, among other things, "the prohibition against retroactive ratemaking," and the Commission's "test year rules." Here again, the court rejected such a broad reading of Finkl and explained its limitations by stating, in part, that:

> …we read Finkl as holding that the Commission abused its discretion in allowing a rider recovery mechanism under the circumstances because demand-side management costs are not of an unexpected, volatile or fluctuating nature so as to necessitate recovery through a rider. Again, we do not read Finkl as holding that the Commission does not have the authority to allow recovery of costs through riders. Given our view of the Finkl court's holding, we view the opinion's discussion of retroactive ratemaking and test year rules as dicta. 255 Ill. App. 3d at 885 (emphasis added).

The rider challenges continued by the Illinois Supreme Court in CUB v. ICC. At the very outset of its discussion, the Court recognized that riders "often include a reconciliation formula, designed to match recovery with actual costs." CUB v. ICC, at 133 (citing to City of Chicago, 13 Ill. 2d 607, 609 (1958)). While not addressing the retroactive ratemaking argument directly, because it was found to be waived, the Court found nothing unusual with the reconciliation procedure terms for the rider at hand. The Court observed that the reconciliation formula used to determine the amount of the rider charge includes a matching of costs incurred with the revenue realized. Id. at 140. In the end, the Court found the Commission's approval of a rider for the recovery of coal-tar clean-up costs to be within its authority and not against the manifest weight of the evidence. Id.

In United Cities Gas Co. v. Illinois Commerce Comm'n, 163 Ill. 2d 1 (1994), the Illinois Supreme Court considered various challenges to a Commission-ordered refund of certain gas costs that occurred in the context of a PGA reconciliation proceeding. In pertinent part, the Court rejected the utility's argument that the refund order constituted retroactive ratemaking. Id. at 12. First and foremost, the Court noted that the Commission's order was entered in a reconciliation proceeding under Section 9-220 of the PUA, which is an express exception to the general prohibition against retroactive adjustment of rates. Id. at 14-15. Second, and as importantly, the Court held that the Commission's refund order "did not disturb any of its prior orders or disallow charges or benefits it had previously approved, as did the Commission in Citizens Utilities when it ordered a deduction from the base rate of tax benefits it had allowed for 24 prior years." Id. at 15. Indeed, the Court observed that despite certain testimony of record, the Commission did not make adjustments to, or rescind orders entered in earlier proceedings so as to retroactively deny the utility any revenues or benefits it had previously allowed. As such, the Court addressed what the rule against retroactive ratemaking prohibits and concluded that the Commission's order did not constitute retroactive ratemaking. Id. at 18.

Analysis

What is common to the seminal cases setting out the retroactive ratemaking doctrine is that once the Commission sets rates, these will be held as just and reasonable so long as the order fixing the rates remains in effect. And, it is well-settled that the Commission sets rates in two ways; by base rates and by an automatic adjustment clause, i.e. the rider mechanism.

Upon careful and studied consideration, the Commission concludes that Rider VBA presents no violation of the rule against retroactive ratemaking. Rider VBA does not disturb either this order or any of the Commission's prior orders. Nor does it disallow charges or benefits previously ordered. The adjustments and true-ups under Rider VBA do nothing to alter or de-stabilize the revenue requirement established here. The rates are what they are. Nor does Rider VBA disturb any of the underling revenue formula components and decisions thereon arrived at through the traditional rate-making process in this proceeding. Nor does Rider VBA suggest that the rates are in any way excessive or insufficient. This order establishes the rate that the Utilities are required to charge and pursuant to Rider VBA the Utilities would only receive the margin revenues that the Commission intends to be recovered. It is not the rates, but the computation of these rates that varies.

The only case that directly considers the rule against retroactive rulemaking in the "true" rider situation is CILCO. And, that opinion strictly limits the application of that doctrine by Finkl to the fact particulars in that decision. In short., we observe, CILCO does not embrace it.

Even if we consider Finkl, however, we see no real analysis there on the rule against retroactive ratemaking. The facts to which the court appears to have applied the rule, i.e., a prudency review procedure, is something common to riders. This was well recognized and looked upon favorably by the Illinois Supreme Court in CUB v. ICC, both in its discussion of reconciliations generally, and in its review of the specific reconciliation mechanism that was at hand. Notably too, the court in CUB v. ICC relied, more than once, on its prior pronouncements in City I.

The sound and enduring analysis in City I makes clear that an automatic rate adjustment clause does nothing to change the fixed and prospective nature of rates approved by the Commission. It explains that:

> [An adjustment] clause is nothing more or less than a fixed rule under which future rates to be charged the public are determined. It is simply an addition of a mathematical formula to the filed schedules of the Company under which the rates and charges fluctuate as the wholesale cost of gas to the Company fluctuates. Hence, the resulting rates under the escalator clause are as firmly fixed as if they were stated in terms of money. City I, 13 Ill. 2d at 613.

This simply means that where a rate schedule approved by the Commission contains a mathematical formula for making future changes in the rate schedule, it is not unlawful under the doctrine of retroactive ratemaking. As such, the GCI and Staff have it wrong. The adjustment contemplated under Rider VBA is precisely the type of adjustment mechanism contemplated in City I which stands as good legal authority.

c. Violations of Test Year Rules.

The GCI contend that Rider VBA would adjust Rate 1 and Rate 2 customer rates on a monthly basis using actual and rate case data from the second month prior to the month of the adjustment determined under the rider. They argue that adjusting rates to reflect one element of the test year's revenue requirement calculation without examining the offsetting expense and revenue component violates this Commission's test year rules.

At the outset, we observe that, in Finkl, the court agreed with the argument that, Rider 22 violated the Commission's own test year rule that require it to view the totality of the utility's financial condition. Id. at 330-332. Reasoning that the DSM costs at issue were properly viewed as ordinary "operating expenses," and that Rider 22 did not utilize a test year, the court concluded that, "DSM costs determined outside of a test year cannot be recovered from ratepayers." Id. at 331.

When considering the rider at issue in CILCO, however, the court flatly rejected arguments based upon test year rule violations and that relied on the Finkl opinion. As was the case with respect to Finkl's finding of retroactive ratemaking, the CILCO court treated Finkl's finding of test year rule violations "as dicta." Id. at 885.

We observe that the Illinois Supreme Court ultimately settled the question in CUB v. ICC, when it directly addressed the argument that a rider violates the Commission's own test year rules. At the outset, the court observed that the test year rule set out at 83 Ill. Adm. Code 285.150, is designed to avert a mismatching of revenues and expenses that might permit a utility to inaccurately portray a higher need for rate increases. Id. at 139. The Court looked favorably on the Commission's explanation that it was not attempting to evaluate or adjust all aspects of the utilities' base rates such that the test year filing was not a prerequisite. Id. In the end, the Court resolved that the test year rule seeks to avoid a problem that is simply "not present" when expenses are recovered through a rider. Id. at 140. The Court also upheld the rider.

Analysis

The Commission considers it clear that there are no test year prescriptions that are violated by Rider VBA. To be sure, the rates we establish arise out of nothing less than a traditional general rate case proceeding where the costs and expenses have been submitted in compliance with the Commission's test year rules. As such, the base rates that are approved in this case and which are the basis for the margin revenues to be recovered under Rider VBA have been evaluated in accordance with the appropriate test year prescriptions. Under the authority of CUB v. ICC, and the soundness of its analysis, we reasonably conclude that there is no test year rule violation with respect to Rider VBA

3. Further Considerations.

The arguments of Staff and the GCI continue and suggest that certain other limitations on riders have been developed by the courts. We consider whether Rider VBA satisfies in these instances.

a. Use of Incentives.

Staff believes that the Utilities suggest that Rider VBA is needed to give them the proper incentives to implement conservation and energy efficiency measures. As such, Staff points out that the Commission has not been given the authority under the PUA to adopt incentive based regulation (Illinois Bell Tel. Co. v. Illinois Commerce Comm'n, 203 Ill. App. 3d 424 (2nd Dist. 1990), and further asserts that adopting a rider to provide for incentive based regulation is improper (A. Finkl & Sons Co. v. Illinois Commerce Comm'n, 250 Ill. App. 3d 317 (1st Dist. 1993)). Staff further notes that, in 1997, and following the decisions in Bell and Finkl, the Illinois General Assembly amended Section 9-244 of the PUA to authorize the Commission to implement alternative incentive-based rate regulation. *See* 220 ILCS 5/9-244. Staff observes, however, that the Utilities do not assert that Rider VBA or Rider WNA are proposed pursuant to Section 9-244, and these riders do not fit under the statute

In other respects, Staff maintains that the holding in Finkl, i.e., that the Commission may not rely on the provision of incentives to justify rider recovery, continues to apply despite the specific incentive-based alternative rate regulation authorized by the amendment of Section 9-244.

We note that, in Finkl, the court reviewed a rider that would recover costs associated with demand-side management ("DSM") programs that ComEd was required, by law, to pursue. One of the arguments raised in Finkl was that the Commission improperly approved Rider 22 "as an incentive to perform a legally required act." Id. at 327. The court observed the Commission to have justified its authorization of Rider 22 on grounds that it removed "a barrier to least cost-planning." Id. at 328. There was no reason to give Edison this illegal incentive, the Court found, where the PUA mandated least cost programs and the utility was under an on-going obligation to comply. Id. This was yet another basis on which the court reversed the Commission's approval of Rider 22. Id. at 327-328.

Not all incentives are unlawful, we find. In Archer-Daniels, the Illinois Supreme Court upheld a Commission order allowing the use of the utility's fuel adjustment clause ("FAC") to recover costs of a fuel contract modification. In its discussion, the Court noted the Commission's expressed concern that the use of FACs would discourage prudent purchasing of fuel by removing the "incentive for utilities to bargain" for the lowest procurement prices. Id. at 399. Given the potential for "disincentives" the Court observed the Commission to have required prudent purchasing practices. The Court found that the utility's action in this situation was "precisely" the type of prudent contract monitoring which the Commission sought to encourage. To disallow recovery of the contract change in this case, the Court reasoned, would create the very danger that the Commission wanted to avoid, namely, removing "incentives" for utilities to engage in prudent purchasing practices. Id.

Analysis

In this instance, Rider VBA does not incent the Utilities to perform any type of "legally required act." If anything, it would serve to "disincent" the Utilities from proposing, as has been done here, the implementation of energy efficiency programs. Unlike the situation in Finkl, however, such energy saving measures are not specifically required under the Act. The Commission recognized this, and our own limitations in this regard, in the Nicor rate case proceeding, i.e., Docket No. 04-0779.

A utility has natural incentives to not be involved in energy efficiency since such activity is far against its self-interest. Thus, this Commission must be mindful, as it was in Archer-Daniels, as to what message it wants to carry and what policy matters it wants to promote. In the process, it must consider not only what is the interest of consumers, but also what this really means for the Utilities.

b. Matters of Fairness.

In their arguments on brief, the GCI raised the question of discrimination in that the Rider VBA mechanism only applies to Rate 1 and Rate 2 customers.

In City II, the court affirmed a Commission order that approved, with modification, Commonwealth Edison Company's ("ComEd") proposed Rider 28 – Local Government Compliance Costs, providing for the recovery of "the marginal costs of providing 'non-standard' service from customers within any governmental unit that mandates such service." Id. at 404. The pertinent issue on review concerned whether Rider 22 creates unlawful rate discrimination. Id. With respect to that claim, the court found that the City failed to submit any evidence before the Commission and failed to meet its burden on appeal. Id. at 411. The court upheld a Commission order approving rider recovery in these circumstances.

We observe that it is Rate 1 and 2 customers who will benefit under energy efficiency measures. It is also these customers that have the best opportunity to conserve. It is also on behalf of these customers that the GCI challenge rate design configurations that would move toward greater cost recovery of fixed costs. The GCI, however, do not mention or analyze any of these matters. It is not discrimination per se, but unreasonable discrimination that must be established. As in the opinion set out above, the GCI have not met their burden here.

c. The Question of Revenues.

Staff and the GCI contend that Finkl specifically rejected the notion of reimbursing a utility for lost revenues due to energy efficiency measures in a rider. As such, they argue that Rider VBA is illegal.

In Finkl, it was argued that the Commission's approval of Rider 22 improperly and illegally authorized Edison to charge ratepayers for lost revenues that, in this context, were "revenues that the utility would have earned but for DSM capability building activities." Id. at 328. This feature of Rider 22, the court observed, failed to "take into consideration Edison's aggregate costs and revenues" and thus, "runs afoul of basic ratemaking principles." The court summarily disposed of the matter by stating that the lost revenue charge here "does not reflect the cost of providing electric service," does not reflect a cost that benefits ratepayers and, further, adds to Edison's revenues without regard to whether Edison's demand or revenues increased because of factors unrelated to DSM programs. Id. at 329.

This was yet another aspect of the court's ultimate and overall determination that costs and revenues are to be determined in a traditional rate case proceeding. To be sure, the Finkl court was largely focused on the costs of DSM programs that ComEd sought to recover in a rider mechanism. Its criticisms of the rider all were based on doctrines of validity to the ratemaking process and it strongly disapproved of the costs not having been included in the company's last rate case.

There is much to distinguish Rider VBA from the facts at issue in Finkl. In that opinion we see that ComEd was seeking to recover "profit loss" and not margin revenues. Id. at 321. The opinion also mentions testimony to the effect that "demand-side resources provide much lower earnings than supply-side resources." At another point too, the court noted that ComEd had not demonstrated that its DSM efforts "to date" had been hindered by lack of an approved cost recovery mechanism, even though it had engaged in DSM conservation activities "well before" the rider was filed. Further, we note that Finkl is internally inconsistent. At one point. it acknowledges that a utility's least-cost plans are to be, to the fullest extent possible, consistent with the statewide plan (Id. at 320), yet the court did not take into account that the statewide plan, which it also mentions, addresses "the recovery of a particular cost associated with demand-side programs due to lost revenues. Id. at 321.

To date, no court has directly addressed Finkl's disposition of the lost revenue argument. In any event, we note, Rider VBA is far different from the rider challenged in Finkl. Unlike the situation in Finkl, Rider VBA does not seek to recover lost profits. Unlike the situation in Finkl, Rider VBA is not linked to earnings lost due to the energy efficiency programs being proposed (and not legally mandated as were the DSM programs). And, in stark contrast to the situation in Finkl, Rider VBA is being proposed in a traditional rate case proceeding. For all these reasons, we do not consider Finkl to limit our authority to consider Rider VBA.

d. Unexpected, volatile or fluctuating costs

In Finkl, the court recognized that riders are "useful in alleviating the burden imposed upon a utility in meeting unexpected, volatile or fluctuating expenses." 250 Ill. App. 3d at 327. But, it also considered the DSM related expenses at issue, i.e., payroll for planning and similar positions; personnel training, education and travel; contractors and consultants costs; out-of-pocket promotion and computer costs; and conducting workshops., to be ordinary expenses. Id. In the end, the court expressed that these DSM costs "reveal no greater potential for unexpected, volatile or fluctuating expenses which Edison cannot control, than costs incurred in estimating base ratemaking." Id.

Notably, in City III, the court considered the City's reliance on Finkl for the very proposition that only unexpected, volatile or fluctuating expenses are properly recovered through a rider. This opinion (and, notably, by the very same appellate district that decided Finkl) makes clear that:

> A Finkl, however, should not be so narrowly construed. In A. Finkl, we stated that "riders are useful in alleviating the burden imposed upon a utility in meeting unexpected, volatile or fluctuating expenses." (Emphasis omitted.) A. Finkl, 250 Ill. App. 3d at 327, 620 N.E.2d at 1148. Nothing in the language of A. Finkl, or the case upon which we relied,

> Citizens Utility Board, 13 Ill. 2d at 614, 150 N.E.2d at 780, limits the use of a rider only to those cases where expenses are unexpected, volatile, or fluctuating. Id. at 628.

Thus, the City III court construed the opinion of the Illinois Supreme Court to mean that there is no requirement and no limitation on the Commission to use a rider mechanism only for costs that are unexpected, volatile or fluctuating. This brings us back to the pronouncements that riders are allowable in the proper case, and under circumstances that reflect the need for pragmatic adjustments.

4. Whether Rider VBA is appropriate in these circumstances.

In City III, the court reasoned that:

> Matters of rate regulation are of legislative character and courts should not interfere with the functions and authority of the Commission so long as its order demonstrates sound and lawful analysis. Id. at 622 (citations omitted).

We accept that our discretionary authority to approve the rider mechanism in any situation must rest, not simply on our inclination, but on the basis of sound and reasoned judgment.

The sum of our extensive review shows that Rider VBA complies with legal requirements, contains no other infirmity, and falls under our authority. The only question that remains is whether, under all of the facts and circumstances, it is a pragmatic adjustment. Thus, we turn our attention to the entirety of the evidence and arguments of record and to all reasonable inferences that may be drawn therefrom.

The record in this case persuades the Commission that Rider VBA is appropriate as it reflects the particulars of declining and variable customer usage patterns and the concomitant revenue recovery impacts for Peoples Gas and North Shore. In our view, this evidence of usage patterns and margin recovery fluctuations calls for a regulatory response. This, we note, is not a novel idea.

The rate adjustment mechanism upheld in City I, was proposed to reflect the changed business conditions of escalating commodity gas costs relative to other utility expenses recovered in rates. Other, but equally valid business challenges, i.e., fluctuating customer usage and the inability to fully recover authorized margin revenues, have here prompted the Utilities to propose Rider VBA,

We consider the underlying conditions and realities that necessitate the Utilities' proposal. No party can or does dispute the high cost of natural gas. Nor does any party dispute the proposition that high gas prices cause certain customers to conserve. Indeed, Staff makes this point clear in all of its testimony on record. While the benefit of conservation to ratepayers is obvious, we are compelled to recognize that it brings negative consequences to bear on the Utilities. And with warmer than normal conditions, a factor outside the Utilities' control, customers naturally reduce their gas consumption. This too, puts the Utilities at risk for recovering their authorized revenues.

Still, the record includes much more that we need consider. Notably, in this proceeding, the Utilities are proposing an Energy Efficiency Program ("EEP"). They have developed this proposal, not solely on their own terms or under their exclusive control, but with the assistance and participation of ELPC and the GCI parties. This is an unusual effort, being far removed from the Utilities' traditional role and well against its basic interests. At the same time, we must acknowledge, it is a laudatory and socially desirable proposal.

While the GCI parties fully support EEP, they pay no mind to what this means for the Utilities. When dutifully considered, however, the effects of the implementation of energy efficiency programs flow exclusively to the benefit of customers. This means that efficiency strategies and improvements, by their very nature, will worsen the Utilities' ability to recover margin revenues in the immediate future. Furthermore, unlike simple conservation activities, efficiency improvements have more long-term sustained effects. In this regard, the Utilities are correct in arguing that our approval of Rider EEP will exacerbate the problem that Rider VBA is intended to address.

Both the Utilities' embrace of energy efficiency programs, and our recognition of customer gas-saving initiatives, compel the view that these developments need be balanced with appropriate adjustments. In our view, energy efficiency is an underutilized resource. All market participants, including the Utilities need to be part of a concerted effort to change the *status quo*. And, in the process, the current regulatory structure may also have to be re-examined and better tuned to accept new factual realities and policy objectives. We have on record in this case, solid reason to find Rider VBA a proper regulatory response for all of the changing realties reflected in these premises.

If there is a different mechanism to be employed in this situation, it would be a straight-fixed variable (SFV) rate design which recovers all fixed costs through fixed charges. Neither the GCI parties nor Staff, however, advocate for this mechanism. Nor have they expressed to this Commission that it is the preferred alternative. In our view, Rider VBA is a reasonable response because it simply involves the recovery of margin revenues that we have already established in this case. In terms of the mechanism itself, the record shows that Rider VBA is designed with symmetry, transparency, and accountability. In these respects, this rate mechanism works to the benefit of both the Utilities and their customers.

We confirm, on the basis of our legal analysis, that Rider VBA meets the criteria for a lawful rider in Illinois. In its operation, Rider VBA would have two primary functions. First, Rider VBA would increase rates to account for margin revenues which the Utilities would be unable to collect, in a given month, due to changes in customer usage. Second, Rider VBA would lower rates to account for any over-recovery of margin revenues by the Utilities, in a given month, due to customer usage changes. These rate increases and decreases would occur under Rider VBA by operation of a mathematical formula that is applied to the margin revenues that will have already been fixed and approved by the Commission in this proceeding. Thus, Rider VBA involves no more than periodic adjustments to a rate that is fixed and approved by the Commission and with such adjustment as determined by application of a set mathematical formula.

This type of rider formulation is the type of mechanism that the Court endorsed in City I, *i.e.*, a rate schedule that contains "provisions which affect the dollars and cents cost of the product sold." City I, 13 Ill.2d at 611.

In the final analysis, we are simply unable to approve only those measures that benefit ratepayers and wholly ignore what the impacts of these benefits will have on the Utilities. To do so could well be unlawful as this Commission is put to the obligation of balancing both the interests of consumers and the interests of the Utilities. *See* BPI, 146 Ill. 2d 175, 208 (1991) (stating that the Commission is charged with setting rates which are just and reasonable not only to the ratepayers but to the utility and its shareholders). Under the whole of the balancing process, we find it sound and reasonable to approve Rider VBA.

We are surely under no obligation to consider the ratemaking practices employed in other jurisdictions. Nevertheless, we cannot deny that decoupling mechanisms are increasingly coming into use across the nation. While this activity does not bear directly on our decision, and the careful way that we have analyzed the proposal, it does show that new and changing realities are indeed calling for new regulatory responses.

The testimony of Staff sets out certain recommended language changes to Rider VBA. First, Staff recommends an annual reconciliation with possible adjustments to ensure VBA is in compliance with the tariff. Second, Staff proposes to change the monthly filing date to allow for Staff review prior to the effective date. Third, Staff recommends that the Utilities be required to perform annual audits on compliance of the VBA. Staff also informs that while one definitional aspect of its recommendations was disputed, it has been resolved, such that the Utilities agree to accept Staff's recommendations. We further note that, despite the opportunity to do so, no other party has proposed changes to Rider VBA. The Commission finds each of Staff's recommendations laudable given that they provide important safeguards to protect ratepayers, and therefore they are adopted. Furthermore, given the unique nature of Rider VBA, the Commission deems it appropriate to implement VBA as a four year pilot program. The Commission further accepts the Utilities' suggestion that a general rate case needs to be filed if Rider VBA is to become effective upon the conclusion of the pilot program._The Commission is mindful of the concerns expressed by Staff, the AG, and City-CUB. Given that this decoupling mechanism presents a case of first impression for the Commission, we will be ever vigilant in our oversight of the deployment and impact of this new Rider.

In furtherance of Commission oversight of this pilot program, the Commission directs Staff to provide Commissioners an annual report on the Companies' rates of return and the effect on that return of Rider VBA, to the extent that is determinable by Staff. In addition, as provided for under Section 9-250, the Commission may, at its discretion, also initiate a proceeding to evaluate the effectiveness of the Rider. We believe that with these safeguards approval of Rider VBA is supported by record evidence in this proceeding and important forward looking policy considerations.

Finally, Rider VBA should only allow the Utilities to recover its fixed costs attributed to small residential service (Serv. Class. No. 1) and general service (Serv. Class. No. 2), and not its variable costs. To this end, the Commission directs the

Utilities to set the VBA formula to recover only its fixed costs (which is 95% for Peoples Gas and 99% for North Shore (NS VG-1.0 REV at 6; PGL Ex. VG-1.0 2d REV. at 8)) and not to include the variable costs.

Because we approve Rider VBA, the Commission finds no reason to discuss Rider WNA, the alternative proposal put forth by the Utilities.

B. Rider ICR

Approximately half of Peoples Gas' system mains (totaling nearly 2000 miles[30]) are cast iron and ductile iron ("CI/DI"). Peoples Gas has been steadily replacing these mains since 1981 with cathodically protected steel and plastic pipe. Since 1981, the target date for completing the replacement project has been 2050[31]. However, if the Commission approves proposed Rider ICR (Infrastructure Cost Recovery), Peoples Gas would endeavor to accelerate the pace of replacement, so that completion would occur in "the 2025, 2030 time frame." Tr. 1542 (Schott). According to Peoples Gas, Rider ICR will enable it to more readily take advantage of main replacement opportunities as they arise without what the Utilities describe as the negative financial consequences such business actions would create under traditional ratemaking methods. Stating this differently, Peoples Gas would attempt to speed up its main replacement program because Rider ICR would authorize recovery of costs associated with capital investments in CI/DI before they are accounted for in Peoples Gas's base rates in its next rate proceeding. As currently quantified, full replacement of Peoples Gas's CI/DI mains will exceed $1 billion. PGL Ex. JFS-1.0 at 9-10.

Rider ICR would apply to customer classes 1H (residential heating), 2 (general service or small commercial) and 4 (large volume demand). PGL Ex. VG-1.0 at 49. Annual rate adjustments would be determined by the amounts recorded in accounts 376.1 (Distribution Mains), 376.3 (Vaults and Regulators), 380.0 (Services), 380.1 (Meter Purchases), 382.0 (Meter Installations) and 383.0 (House Regulators)[32]. PGL Ex. JFS-1.0 at 4. Amounts included in the calculation of PGL's rate base in this proceeding, and amounts associated with main replacements installed before the end of the test year, would be excluded, as would plant installed for new customers. ALJ Ex 1. With Rider ICR in place, Peoples Gas would optimally double the annual rate of CI/DI main replacement, from the current 30 to 50 miles to 60 to 100 miles, Tr. 1542 & 1551

[30] In 1981, cast iron main represented 86 percent, or 3450 miles out of 4031 miles, of main in Peoples Gas's distribution system. Id. By the end of fiscal year 2006, cast iron main had been reduced to 49%, or 1978 miles out of a total of 4025 miles.

[31] A 2002 study found that this target remained reasonable, prudent and superior to alternatives that added or subtracted 10 years. NS-PGL Ex. ED-1.0 at 14.

[32] As initially proposed, Rider ICR would have involved different calculations. Peoples Gas would have netted the average amount of main replacement investments for fiscal years 2004-2006 against Peoples Gas's actual capital expenditures in these same accounts in a fiscal year. If the latter expenditures exceeded the 2004-2006 baseline, the difference would have been billed through a per-customer monthly charge in the following year. However, Peoples Gas later modified and accepted a version of Staff's alternative Rider QIP, which does not contain the baseline expenditure provisions.

(Schott), although Peoples Gas is not committing to achieve that (or any specific) accelerated replacement rate. Id. at 1617-18.

Over the course of this case, Peoples Gas agreed to modifications of Rider ICR proposed by Staff and Intervenors, but rejected a Staff proposal to include a rate of return credit provision in the rider. Staff also recommended renaming the rider "Rider QIP," to mirror a provision in 83 Ill. Adm. Code 656 ("Part 656") for water and sewer utility infrastructure (authorized by Section 9-220.2 of the Act[33]). The modifications Peoples Gas accepted are: 1) that only the costs of the CI/DI main replacement program will be recovered via the Rider through the application of specific eligibility criteria; 2) creation of a separate revenue sub-account; 3) a cumulative cap of 5% of base rate revenues[34]; and 4) an annual reconciliation of prudently-incurred costs. NS-PGL Ex. JFS-2.0 at 4. With these provisos in place, the Utilities annual recovery (of the pre-tax carrying costs and depreciation associated with ICR-eligible expenditures) would be capped at about $18.5 million (assuming Peoples Gas doubled its replacement mileage and replacement costs with Rider ICR in place). Tr. 1566-68 (Schott).

Peoples Gas contends that accelerating the CI/DI main replacement will produce several significant monetary benefits. First, Peoples Gas avers, shortening the approximate 40-year time frame for completing the main replacement program would decrease overall cost, because more current dollars will be used. Second, replacement of Peoples Gas's low pressure system with medium and high pressure will reduce future repairs and increase efficient operation, thereby reducing maintenance costs. Third, Peoples Gas asserts it will be better able to seize significant cost-reduction opportunities (principally street destruction and repair costs) when the City of Chicago or third-parties pursue development projects which permit coordination of main replacements.

Peoples Gas also claims that various operational benefits will result from main replacement acceleration, including meter relocation, regulator vault replacement and reduction in the occurrence of certain service outages. Inside meters could be moved to building exteriors, avoiding the difficulties and customer inconveniences associated with inside inspections. PGL Ex. JFS-1.0 at 7; Tr. at 1551 (Schott). Meter relocation would also facilitate installation of automatic meter reading devices and enhance meter tampering detection. PGL Ex. JFS-1.0 at 9. Ultimately, Peoples Gas insists, Rider ICR "will not result in additional costs to ratepayers over what would be paid in any event for CI/DI main replacement in the aggregate and PGL will not obtain any financial benefit that is different from the rate case treatment which it is normally accorded for capital expenditures. NS-PGL Ex. JFS-2.0 at 9.

Furthermore, Peoples Gas maintains that it cannot obtain the benefits ostensibly associated with acceleration of the Main Replacement Program without Rider ICR.

[33] 220 ILCS 5/9-220.2.

[34] The cap is not an annual limit. It applies to total recovery under Rider ICR over the entire time it is effective. Tr. 1571 (Schott). The cumulative recovery limit is approximately $123 million under current rates, but would be likely higher (because it is based on actual future revenue) under the rates approved in this Order. Id.

"Only Rider ICR adequately addresses the financial impact of the magnitude and uncertainty that accelerating CI/DI main replacement would entail on an ongoing basis. Only Rider ICR would allow [Peoples Gas] the financial wherewithal to respond to external forces and events and thereby manage the unpredictability and uniqueness of the opportunities which acceleration would afford." NS-PGL Init. Br. at 128-29.

With respect to our authority to approve Rider ICR, Peoples Gas argues that there are no rigid prescriptions for employing riders. It claims that rate trackers have increasingly become a reasonable and useful mechanism employed by utilities and approved by regulators to recover the costs of extraordinary expenses. NS-PGL Ex. RAF-2.0 at 32. Furthermore, Peoples Gas emphasizes, the Commission has implemented riders in numerous instances.

Peoples Gas "strongly opposes" Staff's proposal to include a rate of return credit in Rider ICR. NS-PGL Init. Br. at 132. "Rider ICR was intended to be a straightforward mechanism to provide some rate recovery for the cost of acceleration of the replacement of CI/DI main between rate cases. The credit mechanism could have the effect of eliminating recovery of the costs Rider ICR is designed to recover." Id. Peoples Gas stresses that Rider ICR would recover actual expenditures and that "[i]f the credit operates to limit or reduce the ICR revenue, [Peoples Gas] will be precluded from recovering the costs it would have actually expended." Id.

The City supports Peoples Gas's request for approval of Rider ICR. The City underscores the importance of improved infrastructure within its corporate limits. City ICR Rep. Br. at 3. It characterizes the proposed acceleration of main replacements as a "significant effort" toward infrastructure enhancement. Id.

The AG, Staff and CUB all respond that Peoples Gas has not demonstrated the need for Rider ICR. They maintain that Peoples Gas has satisfactorily conducted main replacement since 1981. *E.g.*, "[T]he Existing Main Replacement Program process has worked well from both a safety and financial perspective for both [Peoples Gas] and its customers, and supports rejection of Rider ICR." AG Init. Br. at 76. The AG attributes this ostensible success, in part, to Peoples Gas's Main Ranking Index ("MRI"), by which Peoples Gas prioritizes main segments for replacement[35], so that potentially problematic segments are addressed first. Id. at 78-79. Under Rider ICR, "mains with an MRI ranking of less than 3.0 - currently not scheduled for replacement due to their superior maintenance history - may be replaced." Id. at 79.

Moreover, the AG argues, Peoples Gas has replaced CI/DI main at a satisfactory pace while reducing employee headcount, investing in new utility plant and earning its allowed return. Under Rider ICR, the Intervenors and Staff complain, Peoples Gas could recover additional revenues associated with the accelerated capital additions costs, even while exceeding its authorized return. AG Init. Br. at 83-84 (*citing* Tr. 1614 (Schott)). Accordingly, the AG questions the need for Rider ICR, which "shifts costs and risks to customers between rate case test years, while removing any management

[35] Per the MRI, compromised main segments are scheduled for replacement, while others are earmarked for possible retirement when work on adjacent segments or other circumstances present a propitious opportunity. NS-PGL Ex. ED-1.0 at 15-17. Others are sufficiently sound to remain unscheduled.

incentive to carefully manage and optimize capital expenditure levels." Id. at 81. For its part, Staff emphasizes that Peoples Gas's main replacement program does "not provide any new or enhanced service" and, therefore, merely imposes "an extraordinary price on ordinary gas service." Staff Init. Br. at 192.

The AG also questions Peoples Gas's claim that the low pressure systems subject to accelerated replacement "are particularly susceptible to outages caused by water seepage." NS-PGL- Init. Br. at 124. The AG states that, whatever the general truth in Peoples Gas's assertion, "no particular problem with outages or main leaks has been identified ...Instead…the record shows that leak repair data compiled over the last 10 years under the existing main replacement program validate that 'there has been a steady decline in the number of leaks per mile of cast iron main…confirming that the Company's program is targeting the correct mains for replacement.'" AG Rep. Br. at 52, *citing* PGL Ex. ED-1.0 at 17.

Additionally, the AG, Staff and CUB underscore that Peoples Gas is not precluded from accelerating its main replacements and, if it so chooses, requesting an appropriate rate increase. These parties dismiss Peoples Gas's contention that awaiting the outcome of a rate case would expose it to financial difficulties, asserting that Peoples Gas has not attempted to quantify its alleged financial detriment. *E.g.*, AG Init. Br. at 83-84; Tr. 1621 (Schott). "[Peoples Gas] has done nothing to demonstrate the magnitude of its alleged financial detriment regarding rate base versus rider recovery of capital costs." Staff Rep. Br. at 74

Staff, CUB and the AG also contend that Peoples Gas has not proven that the benefits of rider recovery for accelerated main replacement are as significant as Peoples Gas alleges, or that such benefits outweigh the corresponding costs. As Staff puts it, Peoples Gas's "benefits argument is premised on the view that a rider is allowable on a simple cost-benefits analysis…[T]hey have not even made that showing." Staff Rep. Br. at 73.

Regarding the CI/DI replacement program, Staff states that Peoples Gas "has not demonstrated any variability in costs. Indeed, the only capital expense cost factor [Peoples Gas] identifies is street repair costs (assuming those costs are capitalized), and there is nothing to indicate the magnitude of those costs or the amount of alleged savings from better opportunities to coordinate." Staff Rep. Br. at 74. Accordingly, the opponents of Rider ICR do not believe that significant construction savings (benefits) will result from acceleration.

Furthermore, insofar as operations and maintenance savings result from main replacement (and arise sooner under an accelerated program), the opponents emphasize that such savings will not be recognized by Rider ICR. Thus, while Peoples Gas projects annual O&M leak repair savings ranging from $180,000 to $300,000 per year[36], (Tr.1549-51 (Schott)), Rider ICR would permit Peoples Gas to retain those savings. Staff Rep. Br. at 73. In a rate case, those savings would be "embedded within

[36] The ostensible savings related to *acceleration* of main replacement is actually half of this amount, which includes the replacement mileage completed *without* acceleration.

recorded test year operations and maintenance amounts" where ratepayers would benefit from them. AG Init. Br. at 83-84. Similarly, the AG maintains that "[u]nder traditional ratemaking, in a base rate case, both increases in plant and decreases in plant are reflected in rates simultaneously." Id. at 86. While Rider ICR would provide recovery on new plant investments without a new rate case, "the offsetting depreciation and retirement of existing plant – on which the utilities are still earning a return – would be ignored." Id.

Commission Conclusion

Many of the governing precedents and principles delineating our discretionary authority were previously discussed in this Order. For the purpose of assessing Rider ICR, we will again review those precedents to identify the governing principles that have been developed for automatic adjustment riders over the past 50 years.

In City of Chicago v. Commerce Commission, 13 Ill.2d 607, 150 N.E.2d 776 (1958) ("City I"), the Illinois Supreme Court addressed "the power of the Commission to authorize an automatic adjustment clause in a utility rate schedule, which it described as "a question…of first impression in this court." 13 Ill.2d at 609-10. Emphasizing the "pragmatic" ratemaking power vested in the Commission by the legislature, id. at 618, the Court concluded that the Act "vested in the Commission the power to authorize an automatic adjustment clause to be filed in a rate schedule in the proper case." Id. at 614. The Court then considered whether continuous recovery of gas costs through an automatic adjustment mechanism constituted a "proper case." It concluded that, "under the facts of this particular case," an automatic fuel adjustment rider was not an abuse of Commission discretion. Id. at 614 & 618.

In reaching that conclusion, the Court underscored several attributes of the fuel adjustment rider under review. First, it resolved that gas costs were not the sort of operating expenses requiring a reasonableness assessment by us, because a federal agency performed that function exclusively. "[T]he Commission is without power to consider the reasonableness of the [Federal Power Commission] rates." Id. at 616. In contrast, the infrastructure capital costs that would pass through Rider ICR here are not operating costs, are not reviewed by any other agency before pass-through to consumers and are invariably, per statutory requirement, evaluated for reasonableness by us.

Second, the Court determined that it could not find "that the public or consumer has lost, nor the Commission abandoned, any rights or powers by the authorization of the automatic adjustment clause." Id. at 618. However, the Court stated, "[i]f the Commission, by authorizing the automatic adjustment clause, had given up its rights to initiate proceedings to determine the reasonableness of Peoples rates until the utility should file a new schedule of rates, we might agree with the city's position [opposing the rider]. However, it has not done so." Id. at 617. The Court stressed that then-Section 41 of the Act empowered us to investigate - at any time - the reasonableness of the utility's rates. Id. In the present case, however, Rider ICR would take away our power to utilize the successor statute to Section 41 (Section 9-250 of the present Act) to investigate the reasonableness of Rider ICR, for at least three years:

> If the annual reconciliation fled by the Company shows that the revenues collected by application of the ICR surcharge rider exceed actual [qualifying infrastructure plant] costs *for three or more reconciliation years*, the Commission may initiate hearings under Section 9-250 of the Act…to determine whether the rider should be canceled.

ALJ Ex. 1 (Rider ICR) at 11 (emphasis added)[37].

Additionally, the Court determined that an automatic adjustment clause does not shift the burden of proof away from the utility with respect to the reasonableness of its rates, insofar as that burden is allocated by the Act. City I, 13 Ill.2d at 617. That remains true today.

Moreover, the Court noted that under our then-existing practice - to "allow rate increases based on an anticipated increase in the cost of natural gas to go into effect without suspension," id. at 618 – no proceedings were conducted regarding the reasonableness of gas-commodity rate revisions[38]. Thus, the court characterized the choice between a rider and a series of un-suspended gas rate revisions as "a question of preferable techniques in utility regulation," reviewable only for abuse of discretion. Id. However, because of the above-quoted provision in Rider ICR, our statutory power to initiate a proceeding in which Peoples Gas would carry the burden of proving the reasonableness of Rider ICR would be circumscribed by the rider itself.

In A. Finkl v. Illinois Commerce Commission, 250 Ill.App.3d 317(1993), the Court of Appeals overturned our ruling that Commonwealth Edison ("ComEd") could recover demand side management expenses through a rider, on the ground (among other grounds) that we had violated the rule against single-issue ratemaking. The Court explained the rule: "instead of considering costs and earnings in the aggregate, where potential changes in one or more items of expense or revenue may be offset by increases or decreases in other such items, single-issue ratemaking considers those changes in isolation, ignoring the totality of circumstances." Id. at 325.

In CILCO v. Illinois Commerce Commission, 255 Ill.App.3d 876 (1993), the Court of Appeals upheld our decision, in an industry-wide proceeding, to allow rider recovery by all affected utilities for legally required coal-tar cleanup costs. The court emphasized

[37] Since Peoples Gas did agree to amend Rider ICR to include an annual reconciliation of prudently incurred main replacement costs, prudency and reasonableness must be properly distinguished. Prudency (which we have regarded as an "essential feature" of a rider, CILCO, Docket. No. 90-0127, Order (Aug. 2, 1991)) tests whether a cost is eligible for recovery. Reasonableness tests whether a rate has been properly and lawfully formulated to reflect eligible costs and associated benefits. Essentially, a prudent cost is a component of a reasonable rate. Thus, the fact that a cost is prudently incurred does not necessarily mean that the rate that recovers that cost is reasonable.

[38] Given our lack of authority to review federally determined gas rates, reasonableness proceedings would presumably have been superfluous.

our finding that "these costs will vary widely from year to year depending on the type of remediation activities" and concluded that, unlike the costs in Finkl, they were "the type of unexpected, volatile and fluctuating costs which are more efficiently addressed through a rider." 255 Ill.App.3d at 885. CILCO was reviewed by the Illinois Supreme Court in Citizens Utility Board v. Illinois Commerce Commission, 166 Ill.2d 111 (1995), which held that "the proposed recovery through a rider mechanism, *outside the context of a traditional rate proceeding*, does not violate the prohibition against single-issue ratemaking." 166 Ill.2d at 139 (emphasis added). Unlike the instant case, the "[W]e are not faced with the Commission's treating a single-expense item within the context of a general rate case." Id. at 137-38.

In City of Chicago v. Commerce Commission, 281 Ill.App.3d 617 (1996) ("City II"), the Court of Appeals affirmed our Order authorizing ComEd to collect municipal franchise fees through municipality-specific riders. Such fees had previously been recovered in the aggregate through base rates paid by all customers throughout ComEd's service territory. Although municipal franchise fees are typically predictable and stable, the court stated that nothing in prior precedent[39] "limits the use of a rider only to those cases where expenses are unexpected, volatile or fluctuating." 281 Ill.App.3d at 628.

The court underscored, however, that "[r]iders are closely scrutinized because of the danger of single-issue ratemaking," id., which is "prohibited because it considers changes in isolation, thereby ignoring potentially offsetting considerations and risking understatement or overstatement of the overall revenue requirement." Id. at 627. The court concluded that the franchise fee riders under review did not constitute single-issue ratemaking because "they did not have any impact whatsoever on Edison's overall revenue requirement" and were "'without direct impact on the utility's rate of return.'" Id. at 629.

The foregoing decisions plainly confirm that the Commission has discretionary latitude under the Act to authorize rider recovery in the proper cases. But they also unambiguously establish that the prohibition against single-issue ratemaking (as well as the test year rule) remains in place in rate cases[40]. The Utilities know this. "The only conditions that have been established as prerequisites for riders is [sic] that in appropriate circumstances, *they do not violate test year or single issue ratemaking proscriptions*, or that they reflect certain cost behaviors or unique circumstances." NS-PGL BOE at 60 (emphasis added). Thus, the courts have consistently held that when a utility's actions may affect its overall revenue needs in disparate ways, all impacts of such actions - both expenses and savings - must be considered and balanced in ratemaking[41]. Since the record here does show that accelerated main replacement will tend to generate certain savings, the single-issue ratemaking rule cannot be avoided.

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[39] The court specifically cited Finkl, *supra*, and City I (which it erroneously identified in that context as "Citizens Utility Board").

[40] The rule against single-issue ratemaking and the test year rule were not discussed in City I, the seminal case upholding our authority to use automatic adjustment riders.

[41] This principle has been reiterated in proceedings not involving riders as well. One pertinent example: "it would be improper to consider changes to components of the revenue requirement in isolation. Oftentimes a change in one item of the revenue formula is offset by a corresponding change in another

Nonetheless, Peoples Gas insists that the costs of an accelerated main replacement program would be "unique." E.g. NS-PGL BOE at 64. Even if that were correct - and the Commission disagrees (discussed below) - it would not matter. In rate cases, "unique" issues are not exempted from the rule against single-issue ratemaking. That rule "requires that, in a general base rate proceeding, the Commission must examine all elements of the revenue requirement formula to determine the interaction and overall impact any change *will* have on the utility's revenue requirement, including its return on investment." Citizens Utility Board, 106 Ill.2d at 138 (emphasis in original). We are empowered to accord rider treatment to "unique" costs *outside of* base rate proceedings, not within them (where the single-issue ratemaking rule cannot be disregarded).

On exceptions - and for the first time - Peoples Gas suggests that Rider ICR could be harmonized with the single-issue ratemaking prohibition by including an offset against Rider ICR capital costs of "amounts reasonably attributable to leak repair savings and reductions in deferred taxes occasioned by accelerated main replacement program. [Peoples Gas] could be required to calculate these savings based upon the past year's activity in the annual reconciliation filing, with…appropriate credits." NS-PGL BOE at 63. Staff responds that Peoples Gas could have included a savings offset in Rider ICR at any time while the evidentiary record was still open, but only presented the idea, in general terms, after an adverse recommendation on Rider ICR in the Proposed Order. "[I]t is simply not possible to accord any reasonable review to this new proposal offered in [PGL'S BOE]." Staff RBOE at 49. Furthermore, Staff maintains, the single-issue ratemaking problem is still inherent in the rider." Id. The AG contends that PGL's general proposal fails to capture all the savings PGL's witnesses attribute to accelerated cast iron main replacement (principally, operations and maintenance savings). AG RBOE at 52.

The Commission agrees that Peoples Gas's suggestion is too general[42] and too late to be meaningfully considered, by the parties or by us, at this stage in the proceedings. Also, main replacement costs are capital costs, which need to enter rate base before associated revenues (in the form of a return) can be received. We also hold, in concurrence with the AG, that even Peoples Gas's general description of its suggested offsets shows that all claimed savings have not been included[43].

Ultimately, Peoples Gas's arguments in support of Rider ICR detach from their legal moorings and become a policy plea. "There is nothing about the costs that would be recovered under Rider ICR that are not the subject of routine, traditional Commission ratemaking. What is involved is merely a policy decision to employ a new rate design

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component of the formula. For example, *an increase in depreciation expense* attributable to a new plant may be offset by a decrease in the cost in the cost of labor due to increased productivity, or by increased demand for electricity." BPI v. Illinois Commerce Commission, 146 Ill.2d 175, 244 (1991) (emphasis added).

[42] For example, merely mentioning deferred tax savings (which is all Peoples Gas does in its BOE) is insufficient as a proposal. As Peoples Gas's witness stated in filed testimony, the effect of ICR on deferred taxes is a "straightforward, though very complicated calculation." NS-PGL Ex. JFS-3.0 at 8-9.

[43] *E.g.*, the offsets would not include the reduced maintenance costs that Peoples Gas associates with elimination of low pressure regulating stations. NS-PGL Ex. ED-1.0 at 18.

approach for a truly unique undertaking, as occurred in City I." NS-PGL BOE at 64. Peoples Gas's description of the routine nature of its main replacement investments is correct.

The financial assurances that ostensibly justify a Rider ICR on policy grounds were, and are, available to Peoples Gas under ordinary ratemaking. The fact that Peoples Gas elected not to seek recovery for accelerated main replacement through base rates is significant. Presumably, this is because there is no clear likelihood that standard municipal improvements and private development projects will unfold at a rate or scale that exceed the historic levels reflected in base rates. Nor, apparently, is there clear likelihood that projects that do arise will implicate significant spans of CI/DI mains that Peoples Gas has prioritized for replacement through its MRI analysis (which are also the mains more likely to experience the cost-producing leaks Peoples Gas hopes to avert). Thus, even with Rider ICR, Peoples Gas did not choose to commit to accelerated main replacement. Insofar as Peoples Gas would like to quicken the pace of system modernization, it is free to craft a concrete and sustainable proposal for doing so, and to request base rate recognition of associated investments

We find Staff's argument to be compelling. Staff asserts Part 656, the Commission's preexisting rule for qualifying infrastructure plant surcharge for water and sewer utilities, is a template for Rider ICR. Tr. at 21. We believe that a Rider scripted in accordance with the strictures of Part 656 would ensure that only the costs of the CI/DI Main Replacement Program are recovered through the rider, since the rider would have to meet specific criteria in order to be eligible. Staff Ex. 13.0 at 18-20. The legislature has given guidance on the appropriate methodology to be utilized when drafting a Rider for the Commission's consideration. In the instant case, we observe that Peoples Gas has failed to utilize the parameters of an appropriately drafted Rider.

The Commission is cognizant of the potential benefits of an accelerated CI/DI main replacement program. To be sure, the Commission is keenly aware of the critical need to update and replace the infrastructure that we depend on to deliver our nation's natural gas and energy supply. Unfortunately, in this particular instance, Rider ICR is a deficient vehicle for such a goal. As Staff aptly points out, proposed Rider ICR provides no estimate of the costs or savings under the accelerated program, nor does it demonstrate that the savings will outweigh the additional costs paid by ratepayers under the proposed rider. Staff Ex. 8.0, pp.36-37. Given the paucity of Rider ICR's provisions, the Commission must reject it. In doing so we would like to be clear that the Commission intends no prejudice toward any base rate treatment Peoples Gas may subsequently seek for CI/DI main replacement expenditures. Indeed, the Commission commends Peoples Gas's improvement of its distribution system.

The Commission both supports and understands the need for system modernization. It is clear that Peoples Gas, and probably some other Illinois utilities, have infrastructure components that date back to the turn of the 20th century and many still use technologies that were state-of-the-art eighty years ago. We also recognize that new technology is being applied in every other sector of our economy, to the benefit of both consumers and companies (by lowering costs and providing new products and choices).

This rider proposal reflects a need for the Commission to provide guidance to utilities on the information the Commission needs, at a minimum, to evaluate system modernization proposals, beyond Part 656 and Section 220.2 of the Act. Peoples Gas presented this Commission with no quantitative evidence, no benefit-cost analysis, and no plan as to why or how a $1.0 billion dollar, forty- to forty-five- year investment, should be completed at a much faster rate (i.e., within the next seventeen to twenty-two years).

And yet, we suspect that there are many benefits – quantitative and qualitative – that could have been identified, enumerated and quantified in support of an enhanced system modernization initiative. It is our view that Peoples Gas could have quantified the benefits of Rider ICR. Absent a clear evidentiary record which demonstrates the benefits of the Rider ICR, the Commission must reject the proposal.

So, we are left with a dilemma. To ensure continued reliability, we lean towards increased system modernization, rather than less, all other things being equal. In a general sense, the application of modern technology to the utilities and networks that we regulate and upon which our economy depends makes simple common sense. But unless the proponents of the modernization initiatives provide a more compelling rationale in terms of identifying and quantifying reduced system costs and increased customer benefits, we will never be persuaded that modernization is in the best interest of the ratepayers. Thus, we are likely to have less system modernization in Illinois, rather than more, and the consumers and businesses in Illinois will be the worse for it.

In the case of Rider ICR, the Utilities' proposal is insufficient for the Commission to approve it. It might have been easier to approve the rider had the Utilities included, or the Staff or the Intervenors' elicited, such information as: a detailed description and cost analysis of the proposed system modernization; an identification and evaluation of the range of technology options considered and analysis and justification of the proposed technology approach; a detailed identification and description of the functionalities of the new system, related both to system operation as well as on the customer side of the meter, as well as an identification and justification of functionalities foregone; analysis of the benefits of the system modernization, both to system operation as well as to customers; these benefits should include reductions in system costs as well as an analysis of the range and benefits of potential new products and services for customers made possible by the system modernization; an analysis of regulatory mechanisms to allow companies to both recover their costs of system modernization as well as to flow reduced system costs back to customers; and an identification and analysis of legal or regulatory barriers to the implementation of system modernization proposals.

Since we reject Rider ICR, there is no reason to address Staff's alternative Rider QIP and we will not do so.

C. Rider EEP (Merits of Energy Efficiency Programs and Rate Treatment)

1. Utilities

a) Merits of Energy Efficiency Programs

In In re WPS Resources, Inc., Docket 06-0540, the Commission approved a set of conditions under which the merger proposed in that docket was approved. Condition 27 required that Peoples Gas and North Shore propose a new ratepayer funded energy efficiency program of not less than $7.5 million per year. The Utilities maintain that their proposal, embodied in Rider EEP, satisfies the merger condition.

Utilities witness Rukis testified that the program will be governed by a Governance Board, consisting of five voting members (ELPC, the Utilities, the City of Chicago, a consumer advocacy group, and a North Shore service territory government or consumer member), and one non-voting member from Staff. PGL Ex. IR-1.0 at 6-7. This membership would insure the independence of the Governance Board, and therefore the entire program, from the Utilities. The Governance Board would evaluate and select a Program Administrator, a Contract Administrator, and a Program Evaluator. Id. at 7-8. The independent Contract Administrator would help establish budgets and approve expenditures. Id. at 8. The independent Program Administrator would develop the actual programs, and make reports to the Governance Board. Id. The independent Program Evaluator would make periodic audits and check the performance of the program against established criteria. Id. at 9. The ministerial function of a Fiscal Agent, who would maintain the accounting reports and pay invoices approved by the Contract Administrator, would be at one of the Utilities. Id.

The Utilities anticipate that much of the program would be directed to rebates and other incentives, typically supporting new energy efficient technologies and other gas-saving techniques available for purchase by gas consumers. These could include more efficient furnaces or improved weatherization. PGL Ex. IR-1.0 at 11-15. The programs would be publicized through the media and point-of-sale locations. Id. at 17.

The Utilities note that their proposal of a ratepayer-funded energy efficiency program – leaving aside the issue of whether it is implemented through a rider mechanism – is enjoying broad support from the parties. More specifically, ELPC strongly supports the program, and the City, AG, and CUB support the program as well.

Staff, the Utilities point out, is the only party to oppose the proposed Energy Efficiency Program on its merits. The Utilities believe Staff's worries and quibbles are overstated, and can be summed up in one sentence from Staff's brief: "Staff does not support using utility rates to fund conservation programs." Staff Init. Br. at 205. For their part, the Utilities believe that the proposed program, borne of the Integrys affiliates' experiences in other states, and of the observation by the Utilities and the ELPC as to how programs work in other states, justifies this program for Illinois.

Staff considers the program "unfair," the Utilities note, because not everyone will necessarily participate. Staff Init. Br. at 203. In the Utilities view, however, this is a rather small argument. Many things work this way, including almost everything paid for by taxes. Taxes pay for roads that many citizens will never drive on, and fire fighters that most people, thankfully, may never call. Does this make taxes “unfair?” Surely Staff would not take the argument quite that far. Given all the positive effects of a well-designed energy efficiency program, the Utilities argue, it should not be considered so unfair as to be not worth undertaking as long as the benefits are equally available to all customers. The broadly constituted Governance Board, reporting to the Commission, should be able to design a program with broad appeal. Id. at 3.

Staff also considers the program “inefficient” on account that high prices should do the work. Staff Init. Br. at 204. Even with high prices in the near term, the Utilities believe that some customers will make better choices with an extra incentive. NS--PGL Ex. IR-3.0 at 2. Staff seems to assume that the program will result in measures that are not cost-effective. But if cost-effective measures are chosen – and there is enough experience around the Midwest at this point that good program directors can find such measures – this should not be a real concern. Id. at 3.

As to governance, Staff complains that it is inefficient. The Utilities do not agree, but ultimately will abide by whatever structure the Commission orders. Staff’s proposal is for a Director that has central control. That works in some other programs, and the Utilities can live with it. The Utilities’ focus in setting up the proposed governance was to place a high value on independence from the Utilities. Id. at 5. The Utilities understand that many people would feel that the Utilities have insufficient motivation for the program to be successful if they were to control it. Their organizational structure too, is not the only way to set up a program. But, as proposed, it would be independent.

A funding level of about $7.5 million is appropriate, the Utilities assert, given the size and type of their respective service territories. Id. at 4-5; NS--PGL Ex. IR-2.0 at 2-3. Accordingly, the Utilities urge the Commission to approve this program.

b) Rate/Rider Treatment

The Utilities’ proposed Rider EEP, they explain, will recover their expenses of providing funding for the costs of energy conservation and efficiency programs for their customers through qualified independent third party administrator(s). PGL Ex. RAF-1.0 at 42. The purpose of Rider EEP is to compute, on an annual basis, a monthly charge per customer for each applicable service classification to recover the incremental expenses that support the development and implementation of those energy efficiency programs. PGL Ex. VG-1.0 REV at 40; NS Ex. VG-1.0 3REV at 35. The Utilities are proposing rider recovery for expenses related to the proposed energy efficiency programs for two reasons. First, they note, there is precedent for recovering such expenses through a tariff rider. Previously, Peoples Gas had offered energy efficiency programs as part of a statewide least cost planning initiative and recovered such expenses through Rider 16, Adjustment for Incremental Costs of the Energy Conservation Plan. Second, the Utilities observe that legislation has been offered that may ultimately lead to a statewide energy efficiency initiative. As there is potential for the Utilities’ customers to fund energy efficiency programs under a statewide initiative, the Utilities would not want to burden its customers with the cost of multiple programs. PGL Ex. VG-1.0 3REV at 41-42.

Utilities witness Feingold testified that Rider EEP is a necessary complement to the Utilities' proposed energy conservation and efficiency programs, that Rider EEP ensures that the defined level of funding is made available on an ongoing basis to the chosen service providers, and that the Utilities' applicable customers will be charged only for the program costs actually incurred as the types and mix of implemented programs changes over time. PGL Ex. RAF-1.0 at 42; NS Ex. RAF-1.0 at 39. Further, program cost recovery is considered to be an essential factor in order to achieve utility-sector energy efficiency programs and there should be a clear, reliable and timely regulatory process in place to ensure the recovery of these ongoing expenditures. A rate making mechanism that ensures predictable and timely recovery of energy efficiency and conservation program costs is particularly important for the Utilities because there are added uncertainties surrounding the precise timing of the rollout of their energy efficiency and conservation programs. The uncertain timing with regard to forecasting along with the level and incurrence of program expenditures make Rider EEP well suited for rider treatment as the Commission has acknowledged in other cases. NS-PGL Init. Br. at 135. This programmatic uncertainty makes it difficult to develop a specific amount to represent each year's costs of program implementation. As a result, it is appropriate and necessary for Peoples Gas and North Shore to have the ability to recover such costs through a ratemaking mechanism that can accommodate the anticipated variations in budgeted versus actual costs from year to year. PGL Ex. RAF-1.0 at 43; NS Ex. RAF-1.0 at 40.

The Utilities note that while not recommending a rider, ELPC witness Kubert agrees to the uncertainty regarding the varying levels of expenditure in an EEP program such as the one proposed here. As such, Mr. Kubert acknowledges that in applying spending levels to People Gas and North Shore revenue, an energy efficiency program for their customers would be $8.7 million on the low end up to $36.5 million on the high end. ELPC Ex. 1.0 at 6-7. The Utilities observe that Rider EEP expenses are only known today because the Utilities have agreed to an amount as approved by the Commission.

The Utilities point out that Staff witness Hathhorn recommended certain language changes for Rider EEP and proposed that the Utilities establish an annual reconciliation procedure and internal audit process, as well as change the monthly tariff filing date. Staff Ex. 1.0 at 29. The Utilities would have the Commission know that they have agreed to the revisions suggested by witness Hathhorn. NS-PGL Ex. VG-2.0 at 51.

While the Utilities would accept a deferred account procedure for handling EEP expenditure program recoveries so long as the deferred account process was annual, as opposed to between rate cases, the Utilities do not believe that the objections raised by witnesses Messrs. Brosch and Lazare flatly opposing the rider mechanism are valid. First, the Utilities claim, it is fact that such costs have been previously recovered in a rider is a cogent and persuasive reason for employing a rider to recover EEP programs costs. Not only is the fact indicative of the Commission's employment of riders in general, the Utilities argue, but it also is very indicative that the type of costs to be recovered are highly suited for rider treatment. Indeed, they point out, the difficulty in forecasting and uncertain timing of the level and incurrence of expenditures are the same features that the Commission has determined justify rider treatment in other cases, such as in the CILCO case. In addition, the size of the expenditures to be recovered under a rider should have no bearing on whether the rider should be employed if the costs otherwise are suitable for rider treatment. In this case, the pending legislative proposals discussed by Ms. Grace offer another reason to have a rider in place to capture any eventual additional related costs. In general, the Utilities observe, the objections lodged by the opponents for rider treatment of EEP program costs are more philosophical than anything—those parties simply do not like riders because they view them as "piecemeal" and "nontraditional". These are unpersuasive positions, the Utilities assert, in view of the Commission's long employment of riders.

As the courts point out, "[r]iders are useful in alleviating the burden imposed upon a utility in meeting unexpected, volatile or fluctuating expenses". Finkl, 250 Ill. App. 3d at 327. The Utilities maintain that Rider EEP costs clearly meet these criteria. Other parties have argued that because the Utilities have agreed to spend $7.5 million, i.e., a fixed amount, a rider cannot be used to recover these expenses because where the amount is known, it cannot possibly be "unexpected, volatile or fluctuating". AG Init. Br. at 119; Staff Init. Br. at 210-211; City-CUB Init. Br. at 89-90; ELPC Init Br. at 10-11. The Utilities disagree.

They note that Finkl did not deal "specifically with the very type of expenditure that Peoples Gas and North Shore would recover through Rider EEP". City-CUB Init. Br. at 89. In Finkl, the Utilities observe, the court reversed the Commission's order which utilized a rider to recover costs associated with demand-side management programs because the Rider 22 expenses as the Court found "involve payroll …; personnel training, education and travel; contractors and consultants costs; out of pocket promotion and computer costs; and conducting workshops". Finkl, 250 Ill. App. 3d at 327. These very costs were within the control of the Utility. This is certainly not the case with the Utilities' proposed Rider EEP expenditures, which lack the certainty that could be used to predict in advance expenditures from month to month and year to year and may even fluctuate. NS-PGL Init. Br. at 135.

Moreover, the Utilities assert that the test of whether a rider is justified centers around whether the costs are controllable or are predictable with any certainty. The expenditure for the energy efficiency program at hand, they argue, is neither controllable by the Utilities nor predictable with any certainty. The costs are a function of when the Board approves the funding of projects and this is a function entirely independent of the Utilities. The Utilities believe it difficult to imagine a category of costs that are so totally out of the control of the Utilities and so subject to being expended at times which are dependent upon the actions of third parties. In other words, the Utilities argue, the EEP costs fall squarely into the category of costs that the Illinois courts have found to warrant rider treatment. CUB I, 166 Ill. 2d at 1093.

In their undifferentiated opposition to riders, the Utilities observe the opponents to simply ignore that under the Utilities' proposed Rider EEP, customers would receive immediate and direct benefits of reduced base rates to the extent the expense associated with the energy efficiency and conservation programs decreased from the level used to establish the initial adjustment under the Rider. NS-PGL Ex. RAF-2.0 at

49. Additionally, the Utilities maintain, under Rider EEP customers will not be subjected to the risk of overpaying for a higher level of expenses associated with the energy efficiency and conservation programs when the expenses decrease from the program's initial funding level. According to the Utilities, if this expense component were recoverable through base rates, customers would not benefit from lower rates whenever program costs decreased from the level assumed in the Companies' rate cases. NS-PGL Ex. RAF-2.0 at 51.

The Companies point out that utilities in various states such as Idaho, Massachusetts, Minnesota, Vermont, and Washington have received regulatory approval to recover the direct costs of their energy efficiency and conservation program through tariff provisions such as adjustment riders. PGL Ex. RAF-1.0 at 43-44; NS Ex. RAF-1.0 at 40. Clearly, there is an explicit recognition by the regulators in those states that assured recovery of energy efficiency costs is a necessary step in addressing the barriers many utilities face to investing in more energy efficiency measures. As such, the Utilities argue, the Commission should approve Rider EEP; it would be in step with the evolving policy making trends across the country.

2. Staff

a) Merits of Proposed Energy Efficiency Program

In Staff's view, the Utilites are asking ratepayers to fund a program that is not equitable. In other words, it is funded by all ratepayers, but the direct benefits only accrue to a limited subset of ratepayers. Some ratepayers will see few or no benefits and these may be homeowners that have just upgraded their houses or bought new residences. Others may be renters whose apartment manager does not take advantage of the program. And still others will view the return on their conservation investment as too low even with the benefits provided by an EEP. According to Staff, It is impossible to compare the cost that one individual has to pay with the benefits that others receive, or to determine that one individual's gain is worth more than another individual's loss. Id*.* at 32-36.

The EEP is also inefficient, Staff argues, because the conditions that are most likely to lead to demand for EEP services are those that already provide the best incentive to invest in conservation without an EEP. As gas prices rise, the return to saving gas usage increases, and there are more incentives for individual businesses and consumers to invest in conservation technology without any utility program. No base case for conservation spending absent the EEP has been established, Staff notes, and thus there is no way to measure the incremental effect of the EEP. While the benefits are likely to outweigh the cost for ratepayers receiving program benefits, it is less clear that this is true for ratepayers as a whole. For the entire program to have net benefits, Staff asserts, the value of the gain in technical efficiency from the program must be higher than the cost. Id. at 33-36. And, even if the EEP has net benefits as a whole, Staff does not believe an efficient outcome is guaranteed. Some customers may be induced to invest in projects that are not cost effective by themselves, but the whole program may still have net benefits on average. In Staff's view, efficiency requires that the last individual project undertaken have net benefits.

Staff does not support using utility rates to fund conservation programs. It is concerned that such programs may reduce economic efficiency. According to Staff, ratepayers who may be investing at efficient levels absent the program might be induced to start investing in too much conservation by investing in projects that have negative net returns. This reduces economic efficiency. In contrast, a program financed through an income or property tax would have a smaller decrease in efficiency.

Staff notes that various parties to the docket make claims of aggregate or system-wide benefits. Staff points out that the claims are not well-founded. The parties have offered only vague assertions to bolster their claims for large system-wide benefits. Staff strongly disputes the parties claim that it has been demonstrated that EEP can lower gas prices in Chicago.

Staff also finds the EEP design to be flawed. Staff has several concerns with how the EEP is to be administered. Foremost, Staff considers that the lines of command are not clear, i.e., it is not clear who controls which functions and who makes what decisions. This is important to Staff, since it does not appear that the Administrators are accountable to anyone. Staff believes that the organizational chart for the program (NS Ex. IR-1.1 and PGL Ex. IR-1.1) demonstrates the validity of this concern. There is an arrow from the Control Administrator to the Board and an arrow from the Board to the Program Administrator, but the chart does not indicate to whom the Administrators report. There also does not appear to be any way for the Board to limit administrative costs. If administrative costs are too high, Staff asserts, the extra costs will seriously undercut the EEP's effectiveness. Staff Ex. 12.0 REV. at 36-37.

Staff recommends that the organization be one that is accountable and efficient. The Board should appoint a Director that has clear authority to act both with respect to employees and programs. Employees should be enabled to select and administer the programs under the authority of the Director. It is not clear to Staff that the Program Evaluators need to be a separate group of employees such that the Director should use the inputs of the employees to select programs that the employees can evaluate. One way to help make the process effective is to conduct periodic management audits and use annual reports about the programs' effectiveness. Staff urges that these changes should be made no matter the method of rate recovery, i.e. rider or base rates. Id. at 37. An important control that the Commission should impose on the EEP is to have a binding constraint on the amount of administrative costs that are incurred, and by requiring the Companies to periodically report their EEP overheads. Id.

Finally, in the event that the Commission approves EEP, Staff agrees with the Companies' witness Rukis that EEP not be funded above $7.5 million per year. In addition Staff recommends that the Commission order the Companies to be responsible for the prudent choice of programs and efficient implementation of those programs. The Companies must be ultimately responsible for any EEP expenditures authorized. Id. at 38.

b) Proposal for Rider Recovery of EEP Costs

Staff observes that the Companies' proposed Rider EEP is designed to charge, recover, and reconcile the budgeted and actual costs of an energy efficiency program for the eligible rate classes S.C. 1H and S.C. 2. North Shore Ex. VG-1.0 2REV at 35-36. The Companies propose a constant annual budget of $7.5 million, proportionally divided between the two Companies, based on their share of the rate base. Id. at 38. The Companies proposed that the rider work thusly: in December of 2007, the Companies would calculate the "Effective Component" by dividing the 2008 budget ($7.5 million) by the forecasted number of customers (861,134) and dividing it by 12 months to determine the per customer monthly increase for 2008. Id. at 35-36. Under or over estimating the budget will then be reconciled in March of 2009, when the Companies will calculate how much customers over or under paid in 2008. That amount, with interest, will then be amortized over the next nine months. Id. at 36.

The process then continues much the same way, except, the Companies, in accordance with their proposal, can carry-over up to 75% of the 2008 budget into 2009; subsequently they will carry 50%, 25%, and then 10% through the life of the program. (Id.) In December of 2008, the Companies will once again determine the "Effective Component" or customer charge for 2009 customers based on forecasted customer numbers. This charge will then be reconciled in March 2010, where the Companies will calculate if they should recover additional funds for program expenditures above the combined 2009 budget and the carry-over budget from 2008, or refund an over recovery of customer charges monies unspent under the carry-over limit. Id. This reconciliation will then be submitted to the Commission in a docketed reconciliation proceeding. Staff Ex. 1.0, Attach. D, p. 3. The Company will also file, with the Accounting Department of the Commission, an annual audit on July 1 of each year. Id.

Staff notes that the Commission can approve "the direct recovery of unique costs through a rider when circumstances warrant such treatment." CUB v. ICC, 166 Ill.2d at 136. One standard for recovery of expenses through a rider is that the expense to be recovered is volatile, unexpected, and likely to fluctuate. CILCO v. ICC, 255 Ill.App.3d at 885. In Staff's view, however, the Companies have not demonstrated that costs underlying the operating expenses associated with an energy efficiency program are or will be, volatile, fluctuating, or unpredictable.

According to Staff, the Utilities' arguments in support of rider treatment fall short. First, Staff notes that the prior rider recovery of the incremental cost of energy efficiency and conservation measures occurred in the context of conducting pilot energy conservation programs to test the effectiveness of various types of conservation programs by all utilities. In re An Investigation Concerning the Propriety and Appropriateness of the Development and Implementation of Energy Conservation Programs by The Peoples Gas Light and Coke Company, Docket No. 83-0034, 1993 Ill. PUC LEXIS 48, at 2 (Order Feb. 10, 1993); In re An Investigation Concerning the Propriety and Appropriateness of the Development and Implementation of Energy Conservation Programs by The Peoples Gas Light and Coke Company, Docket No. 83-0034, 1989 Ill. PUC LEXIS 417, at 3 (Eighth Supp. Interim Order, Nov. 8, 1989)) This is hardly the situation in the instant case. Further, Staff observes that the Companies cite to no order by the Commission explaining the basis on which rider recovery was approved, so that the fact of prior approval is of little assistance in evaluating the current proposal. Moreover, while the Commission did generally find that the costs of energy efficiency and conservation measures were recoverable through riders in the 1990s, that practice was rejected by the courts. *See* A. Finkl & Sons Co. v. Illinois Commerce Comm'n, 250 Ill. App. 3d 317 (1st Dist. 1993).

In Staff's view, Ms. Grace's testimony completely contradicts any argument that such costs are volatile, unpredictable, or fluctuating. The costs of the Companies' proposed energy efficiency program is budgeted at $7.5 million, but the Companies, with their experience in offering energy efficiency programs know, and Ms. Grace testified, that it would take a few years to build up to the budgeted annual amount. When the Companies drafted Rider EEP, they predicted a slow start to the programs and embedded a mechanism that allowed for a carry over of 75% of the budget in the first year, 50% in the second, 25% in the third, and 10% every year there after. NS Ex. VG-1.0 2REV at 36; PGL Ex. VG-1.0 at 40.

Furthermore, Staff believes that the discretion offered under the rider for the Companies to carry over amounts from one year to the next raises a concern. This significant funding flexibility could result in a significant gap between the budgeted expenditures and the amounts actually spent. This would create a gap between the policy objectives guiding the Commission's approval of the rider and the amount that is actually spent on the associated programs. Staff Ex. 8.0 at 34. According to Staff, the magnitude of carry-over provision raises further questions about the program itself. The level of spending flexibility raises questions about the degree of progress in planning and developing the programs and what kinds of programs ratepayers will receive for their contributions to Rider EEP. Id. For this reason, Staff cannot recommend that the Commission blindly subject ratepayers to an out-of-rate-case rate increase.

Staff notes Peoples Gas and North Shore argue that the size of the expenditures to be recovered under a rider should have no bearing on whether the rider should be employed if the costs are otherwise suitable for rider treatment. Id. Staff does not agree. Staff observes that there is a cost associated with implementing and administering riders and this cost can be significant. Thus, if the revenues to be recovered under the rider are small, then the costs could outweigh any possible benefits. In any event, the amount of revenues to be recovered is an important consideration in deciding whether to approve the rider.

If the Commission determines it is appropriate for the Companies to recover funds necessary to implement various energy conservation and efficiency programs through a rider mechanism, Staff recommends the Commission adopt the language changes which are reflected in legislative style in Attachment D, Staff Revised EEP, to Staff Ex. 1.0. The changes are: 1) to reflect an annual reconciliation with possible adjustments to ensure the EEP is in compliance with the tariff; 2) to change the monthly filing date to allow for Staff review prior to the effective date; and 3) to require the Companies perform annual internal audits on compliance of the EEP. Staff notes that the Companies stated no opposition to these proposals. NS-PGL Ex. VG-2.0 at 51.

3. ELPC

a) Merits of Proposed Energy Efficiency Program

The ELPC maintains that consumers who directly participate in well-designed energy efficiency programs benefit from reduced gas usage and lower bills. Energy efficiency measures can cost half per Mcf saved compared to the cost of natural gas. According to the ELPC, a review of leading utility natural gas energy efficiency program results indicates that such programs typically have more than a 2 to 1 'benefit to cost ratio,' and save natural gas at a cost of around $2.50 per Mcf. That is less than half the forecasted wholesale cost of natural gas over the next 10 years." ELPC Ex. 1.0.

The ELPC points out that these savings are documented in the many programs under operation in other states. Natural gas energy efficiency programs have been implemented by utilities in over 20 states, including Iowa and Wisconsin. Id.

> In 2005, the average residential natural gas consumption in Iowa was 791 therms, in Wisconsin 823 therms, in Minnesota 942 therms. In contrast, the average Peoples Energy residential customer used 1,231 therms and North Shore Gas customer used 1,392 therms. This comparative energy consumption data is attached as Exhibit 1.2. While there are a number of factors driving these differences, including the size and age of the housing stock, it suggests that long-established energy efficiency programs in these neighboring (and colder) states have played a role in reducing gas use. It also suggests that there is significant untapped energy efficiency potential in Illinois.

Id.

The ELPC notes, for example, that if a residential customer made an investment that has an average cost of $100 per year over the life of the energy efficiency improvement (normally 15-20 years), assuming a conservative $2 payoff on $1 investment, on a yearly basis, he or she could recoup that $100 plus the approximately $100 average rate increase that Peoples small residential heating customers would pay under the Companies' proposed rate increase. According to the ELPC, this does not even consider that it is the norm within such programs to provide participants with energy efficiency improvements at discounted rates so the payoff to the customer on their investment would likely be even higher.

To be sure, the ELPC argues, a goal of in excess of $100 in annual savings per residential participant is extremely reasonable. In Massachusetts, a program providing rebates on high-efficiency furnaces is seeing savings of 185 therms annually per customer. ELPC Ex. 1.3 at 50. In Vermont, a residential retrofit program that offers energy audits and across the board recommendations of energy efficiency measures is providing individual customers with savings of 510 therms annually. Id. at 72. Finally, a similar residential retrofit program in New York is providing individual customers with annual savings of 347.9 therms. Id. at 64. Consequently, the ELPC suggests, it would be reasonable to expect savings in Illinois comparable to the median program in New York. At a conservative estimate, reducing gas usage by 347.9 therms annually would provide customers with $141.25 in annual savings. Such savings would more than cover residential participants' investment in the program and improvements and even offset part of the Companies' proposed rate increases.

According to the ELPC, the proposed energy efficiency program would benefit Illinois' overall economy. The ELPC points out that, there is essentially no natural gas produced in Illinois, and as such, the state is entirely dependent on natural gas imported from other states and countries. PGL Ex. IR 1.0, lines 89-90. Every dollar that consumers spend on the commodity portion of their natural gas bill, the ELPC argues, is a dollar transferred out of Illinois' economy. The total drain on Illinois' economy resulting from buying out-of-state natural gas is over $7 billion per year. ELPC Ex. 1.0.

In the ELPC's view, energy efficiency programs in Illinois also have the potential to produce a net gain of nearly 6,500 jobs and $220 million in additional net annual employee compensation in Illinois by 2010 and 13,000 net new jobs and $440 million in net additional annual employee compensation by 2020. Id. Ex. 1.0. In sum, the ELPC argues, energy efficiency brings an enormous benefit to Illinois' economy over buying out-of-state natural gas.

As a further benefit, the ELPC maintains that energy efficiency programs help to reduce total demand for natural gas, which puts downward pressure on natural gas market prices. While ELPC acknowledges that the Companies' proposed energy efficiency program alone might not affect wholesale natural gas prices, it is a step towards reductions in natural gas prices.

There are many aspects of the program which assures that dedicating funding to the EEP is a prudent expenditure. First, the ELPC points out, there is the accountability built into the structure of the program. As described in great detail in Company witness Rukis' testimony, the Companies have proposed a structure for the EEP that holds those responsible for the program accountable but also maintains the program's independence from the Companies. The Governance Board, whose members would be accountable to, and representative of, all interested parties, is at the top of the hierarchy of the program.

Second, the ELPC maintains that the proposal assures accountability through the numerous audits and evaluations. The Program Evaluator would perform periodic audits of the program, the ELPC explain, and prepare annual reports. Id. at lines 188-190. And, he or she would also provide other periodic evaluations or reports as required by the Governance Board. Id. at 190-93. The ELPC further notes that the Companies also recommend a periodic review by an independent third party to assess how well the overall structure and process of the programs are performing and whether any changes should be made. Id. at lines 211-32. Ultimately too, there would be accountability before the Commission. Because the Commission maintains authority over Peoples and North Shore and authority over the level of rates charged, the Commission maintains the ability to review how the program is running. Tr. at 104. Specifically, all reports, audits, and evaluations could be filed with the Commission and with exhibits added in the next rate case. Id. at 104-105.

According to the ELPC, the program is a prudent use of funds because it assures energy efficiency projects with high paybacks. Despite the fact that energy efficiency can save utility customers money, the ELPC contends that there is still underinvestment in energy efficiency in Illinois. By way of example, one can look at the market penetration of high-efficiency furnaces. In Illinois the market penetration is 30%, while in Wisconsin, where there has been an energy efficiency program for many years, the market penetration of high-efficiency furnaces is 70%. Tr. at 1421-22. The ELPC has well-explained the many reasons for the underinvestment in energy efficiency, to wit:

> lack of information regarding potential energy efficient improvements and their benefits; a focus on first-cost versus life-cycle costs when constructing buildings and buying appliances; uncertainty over length of time in homes which discourages longer payback investments; unreasonably short payback requirements by businesses; a tendency by builders to comply with minimal code requirements; and split incentives between landlords and tenants.

ELPC Ex. 2.0. Because energy efficiency costs less per MCF saved than natural gas, the ELPC asserts that energy efficiency programs and policies are necessary to increase the investment in energy efficiency to a level at which individuals and society will reap the most benefit. ELPC Ex.1.3 and 1.4.

The ELPC points out that the program has measures which assure energy efficiency projects with the highest paybacks. It is of record that "One of the first things that the governance board should accomplish is a market potential study which will further ensure the best and wisest use of available resources by identifying the opportunities to use the funds." Tr. at 97. There will also be a "bidding process that will ensure that we get the lowest-cost programs." Id. at 98. Given this telling evidence, the ELPC maintains that the EEP is a prudent expenditure and necessary to accomplishing broad adoption of energy efficiency measures.

Finally, the ELPC recognizes the Commission to have full authority to direct the adopting of energy efficiency programs in this rate case Order under its broad statutory authority. 220 Ill. Comp. Stat. 5/9-250. The ELPC points to language in numerous states as sources for this authority and asks that it be exercised in this case. And, the ELPC notes that the Commission itself has recognized that energy efficiency reduces energy costs for consumers when it stated that:

> We believe that smart energy efficiency programs will have two effects. First, they will lower the cost of heating for the home or business participating in the program. Second, targeted correctly, they will reduce the amount of high cost natural gas that Illinois has to buy, thus reducing everyone's costs, as well.

The Commission further indicated that:

> [S]mart energy efficiency programs . . . , targeted correctly, . . . will reduce the amount of high cost natural gas that Illinois has to buy, thus reducing everyone's costs, as well. . . . . Increased energy efficiency that decreases the individual household or business costs of natural gas and electricity

> and—at the same time—reduces the amount of high cost energy we have to buy—lowers prices for everyone and appears to be the premier option that Illinois has for lowering customer energy bills.

Northern Illinois Gas Company, Docket No. 04-0779, Order at 193 (September 20, 2005).

For all these reasons, the ELPC joins in asking approval of the Utilities' EEP in this case.

b) Proposal for Rider Recovery of EEP Costs

The ELPC maintains that recovery for the Energy Efficiency Program should be through base rates, and not a rider. In the ELPC's view, the mere fact that the EEP is a new program and new expense area for the Companies does not suffice for such treatment. Typically, the ELPC argues, the only expenses that justify riders are those which are outside the utility's control or are volatile and unpredictable. The energy efficiency program is not outside the utility's control—indeed, the utilities in this case are proposing the expenditure—and such is neither volatile nor unpredictable. ELPC Ex. 1.0. It may just be the opposite, i.e., stable and predictable, because it is fixed at the same amount every year.

The ELPC recognizes that specific legal standards must be met before rates can be recovered through a rider and the circumstances must "warrant such treatment." Citizens Utility Board v. Illinois Commerce Comm'n, 166 Ill. 2d 111, 138 (1995). As such, the expense must be volatile, unexpected, and likely to fluctuate. Id. In terms of facts, the ELPC considers the case of A. Finkl & Sons Co. v. Illinois Commerce Comm'n, 250 Ill. App. 3d 317 (1st Dist. 1993), to be precisely on point. In that case, the ELPC explains, the court was considering the appropriateness of the use of a rider for recovery of costs for a demand side management program, which in essence, is an energy efficiency program, and it held that demand side management costs could not properly be recovered through a rider because they were not volatile nor were they beyond the Company's control. Id. at 327. The court also noted that the rider was not proper because the amount of dollars to be recovered through the rider was not significant and the costs were recoverable through the usual base rate mechanism. Id. *Cf.* Citizens Utility Board v. Illinois Commerce Comm'n, 166 Ill. 2d at 138-39 (holding a rider appropriate because there were "wide variations and difficulties forecasting the costs" to be recovered). In the present case, where the program costs are a set $7.5 million per year, the ELPC believes that the costs cannot be described as volatile, unpredictable, or likely to fluctuate. According to the ELPC, a deferral accounting mechanism can be employed to track and reconcile differences between recovery through base rates and disbursements made under the program. GCI Ex. MLB-1.0 at 72.

4. GCI

a) Merits of Proposed Energy Efficiency Program

The GCI note that in the recent Peoples Gas/North Shore Gas merger proceeding, the Utilities agreed to propose to implement energy efficiency programs for both companies, and in an annual aggregate amount of $7.5 million, to be funded by ratepayers. *See* Docket No. 06-0540, Appendix A, Conditions 27-30. The AG, the ELPC, CUB, the City, and other intervenors were signatories to the agreement. Between the approval of the merger settlement and the filing of this rate case, the Companies met with representatives from the AG's Office, ELPC and other stakeholders for discussions on implementation of the programs. In an effort to ensure that the energy efficiency programs are developed and marketed by individuals and entities with experience in the implementation of EEPs, the Companies and the aforementioned stakeholders agreed that a third-party Governance Board structure would provide an efficient foundation for program creation and implementation.

GCI notes that the Act makes multiple references to the mandate that utility rates be least-cost. Section 1-102 of the Act states that "the General Assembly finds that the health, welfare and prosperity of all Illinois citizens require the provision of adequate, efficient, reliable, environmentally safe and *least-cost* public utility services at prices which accurately reflect the long-term cost of such services and which are equitable to all citizens." 220 ILCS 51-102. The GCI also note that the General Assembly has further defined "efficiency" as "the provision of reliable energy services at the least possible cost to the citizens of the State". 220 ILCS 5/1-102(a). Further, they observe Section 8-401 to require that every public utility subject to the Act, provide service and facilities which are in all respects adequate, efficient, reliable and environmentally safe and which, consistent with these obligations, constitute the least-cost means of meeting the utility's service obligations. 220 ILCS 5/8-401.

Notably, the GCI observe that in a recent rate case order, i.e., Docket No. 04-0779, the Commission committed itself to having energy efficiency programs implemented on a statewide basis for all gas and electric utilities in time for the 2006 heating season. In making this commitment, the Commission stated:

> We feel strongly that we must move with all deliberate speed on this issue. …Given the dire projections of energy costs, time is of the essence for the deployment of energy efficiency programs on a statewide basis. Nicor, Order at 193.

Even as that hopeful goal never materialized, the GCI parties observe the Commission to have made clear its belief that EEPs are a worthwhile utility expense, by stating that:

> the Commission understands the importance and critical necessity of using energy efficiency plans as strategic tools to protect Illinois consumers and reduce their energy costs. …We believe that smart energy efficiency programs will have two effects. First, they will lower the cost of heating for the home or business participating in the program. Second, targeted correctly, they will reduce the amount of high cost natural gas that Illinois has to buy, thus reducing everyone's costs, as well. …Increased energy efficiency that decreases the individual household or business costs of natural gas and electricity and – at the same time – reduces the amount of high cost energy we have to buy – lowers prices for everyone and appears to be the premier option that Illinois has for lowering customer energy bills. Id. at 192.

The GCI recognize Staff witness Rearden to have presented the primary attack against energy efficiency programs in general, and ratepayer funding of them in particular. At the outset, GCI observe, that he would unfairly apply a higher standard of equity for energy efficiency than the Commission applies for other costs. Indeed, the GCI point out that there are numerous utility expenditures that will benefit only a limited subset of customers, despite the fact that all customers pay for the expenditure. For example, they note, when Peoples Gas or North Shore Gas extends a distribution line or provides service to a new home, the costs are spread over all customers, wherever located, although only a very limited number of customers directly benefit from the expenditure. *See, e.g.*, ELPC Ex. 2.0 at 4. According to the GCI, Staff's inequity argument is defective for another reason, i.e., it presumes that customer desire and need for EEPs is a static phenomenon. In reality, the GCI assert, customers move in and out of apartments and houses, and their need for energy efficiency assistance and initiatives is ever-changing. Moreover, GCI contend that although not all customers will benefit by directly participating in an energy efficiency program under the program, large-scale energy efficiency programs can reduce demand for natural gas, thus exerting downward pressure on gas prices. ELPC Ex. 1.0 at 5. In such an instance, they argue, all customers – even those who do not participate in energy efficiency programs – benefit from lower gas prices.

In this regard too, the GCI note, Ms. Rukis testified that Illinois is dependent on natural gas that is imported from other states and countries. PGL Ex. IR-1.0 at 4; NS Ex. 1.0 at 4. She noted that natural gas prices have increased sharply, which place not only a financial burden on residential and business customers, but also affect the ability of the State of Illinois to grow its economy and be competitive. Id. at 4-5; Id. at 4-5. She further concluded that, "Energy efficiency programs can reduce expenditures for importing natural gas supplies and assist all customers in better managing their energy use and lowering energy bills." Id. at 5; Id. at 5. She added that the Companies' proposed EEP can "reduce the total amount of therms that need to be purchased by the Companies, thus reducing the expenditures relating to the purchase of natural gas." NS-PGL Ex. IR-3.0 at 6.

ELPC witness Kubert testified that properly designed EEPs can save natural gas at a life-cycle cost of one-third the cost of purchasing and distributing that same amount of natural gas. ELPC Ex. 1.0 at 2. He noted that neighboring Midwest states, where EEPs have been implemented, have lower average residential natural gas consumption than Peoples Energy consumption rates. Id. at 2, 3. He added that despite high natural gas costs, homeowners and businesses continue to under-invest in energy efficiency for a number of reasons. Id. at 3. Ratepayer-supported EEPs help to overcome the barriers "by providing financial incentives, technical assistance and education to residential and commercial customers, retailers, distributors and contractors." Id.

According to the GCI, the record shows that Dr. Rearden's criticisms of the proposed energy efficiency program are without foundation. Indeed, the evidence indicates that the program can have significant benefits for Peoples Gas and North Shore customers and the State of Illinois. ELPC witness Kubert explained that Illinois residents spend almost $7 billion per year on natural gas. Id. And because, as Dr.

Rearden conceded, there is little, if any, natural gas produced in Illinois, Sep. 11, 2007 Tr. at 720-21, these dollars are directed out of state. In contrast, Mr. Kubert testified that energy efficiency program dollars are used in Illinois to pay contractors and vendors who implement these programs, thereby creating jobs and net economic benefits for Illinois. Id. at 4. Mr. Kubert cited an ACEEE study showing that by 2010, a moderately aggressive five-year regional energy efficiency program would result in savings of more than $1 billion for Illinois consumers, produce a net gain of nearly 6,500 jobs and an additional $220 million in net employee compensation. Id. .

While no party denies that high natural gas prices can be an incentive for conservation, GCI note that even Mr. Rearden has acknowledged that utility customers may need and benefit from the extra help an EEP provides. Tr. 722-24, 734. And, Mr. Kubert provided evidence to show that there is an underinvestment in energy efficiency as a whole in Illinois. He testified that Illinois' market penetration rate for high efficiency furnaces is around 30 percent. Tr. 1421. But, in Wisconsin, which has had gas (and electric) EEPs for many years, the market penetration for these furnaces is well in excess of 70 percent. Tr. 1421-22.

The GCI dispute Staff claims that the EEP is inefficient because high gas prices are sufficient to cause persons to invest in energy efficiency. Staff Init. Br. at 204. In their view, Staff's argument assumes a perfect market and that people have all the information and resources necessary to invest in energy efficiency programs that are in their economic self-interest. Of course, GCI contends, no such perfect world exists. Even Dr. Rearden conceded that some customers may not implement energy efficiency or conservation measures because they lack the requisite information that it is in their best interest to do so. Tr. at 708-09. And, he also admitted that "there is, at the very least, a subset of Peoples Gas and North Shore ratepayers out there who could use financial assistance in helping them make rational energy efficiency investments." Id. at 723-24. Further, the GCI observe Dr. Rearden to have added that some consumers may have sufficient funds to pay their monthly gas bills, but lack the necessary funds to make a larger outlay for energy efficiency measures even if it is in their self-interest to do so. Id.

The GCI understands Dr. Rearden to make clear that he is opposed to funding EEPs through utility rates on both a theoretical and practical basis. Tr. 726. He explained that he believes that energy efficiency programs should be financed through an income or property tax. Tr. 727; Staff Ex. 12.0 at 35. And, he stated the view that EEPs should not be provided in either Peoples' or North Shore's service territory until such time as state or federal government officials require their implementation statewide. Tr. 727-728. This shortsighted view of EEP funding should be rejected the GCI argue. In any event, they noted Mr. Kubert to explain that, because of the large customer base and the relatively small size of the EEP, a ratepayer funded program has essentially the same impact as a taxpayer funded program. ELPC Ex. 2.0 at 6.

In terms of Staff's objection to the governance of the program, the GCI consider these concerns to have no merit. ELPC witness Kubert explained in detail the structure of the governance board and why it is appropriate for a program of the size being considered in this case. ELPC Ex. 2.0 at 6-7. Peoples Gas witness Rukis described in even more detail the operations of the governance board and the controls that will be in place to ensure effective oversight and implementation of the programs. PGL Ex. IR-1.0 at 5-11. The GCI submit that it is hard to understand Dr. Rearden's concern. Nevertheless, the City and CUB would not object if the Commission were to prescribe additional oversight.

Ms. Rukis, who has been involved since 1987 with public benefits programs, including low income, energy efficiency, distributed generation and renewables projects, testified that the Governance Board's voting procedures, which would not give any one entity the ability, acting alone, to approve or reject any matter coming before the Board, would ensure the Board's independence from the Gas Companies. The anticipated duties of the Board would be to oversee the creation and issuance of Request for Proposals and select (1) one or more Program Administrators for implementation of EEPs; (2) a Contract Administrator; and (3) a Program Evaluator. An employee of the Companies would act as Fiscal Agent and account for the funding approved by the Commission. Ms. Rukis testified that "(t)he Board would establish, in consultation with the Contract Administrator, the general Program goals and performance criteria, e.g. which types of programs should be offered to which customer segments and in what timeframe."

As explained by Ms. Rukis, the Contract Administrator would assist the Board with setting program goals, and performance criteria and budgets. This individual also would help draft the requisite Requests for Proposals and approve program spending and invoices from the Program Administrator(s) and Program Evaluator. Id. The Program Administrator(s) would be responsible for: (1) developing detailed program designs in cooperation with the Governance Board and the Contract Administrator; (2) delivery of agreed-upon programs; (3) hiring of sub-contractors for program delivery as necessary; and (4) delivery of periodic performance reports as required by the Board. Id. The Program Administrator(s) also would be responsible for preparing and delivering to the Governance Board any reports and information required by the Board. The Program Evaluator would perform periodic audits on the performance of the programs against established performance criteria, and also prepare annual reports, any other kind of reports requested, for the Governance Board. Id. at 9. The Program Evaluator would be independent of the Companies, the Contract Administrator and the Program Administrator(s). Id.

Finally, the Fiscal Agent would maintain accurate accounting records, pay invoices as approved by the Contract Administrator from the Program Administrator(s) or any subcontractors, and would help to prepare periodic financial reports. This Peoples or North Shore employee would not be involved in decisions about what to fund or how much to spend on particular programs, Ms. Rukis noted. Id. Any issues and concerns regarding disbursements associated with the programs would be directed to the Board by the Fiscal Agent for review and resolution. Id. Ms. Rukis testified that the Fiscal Agent would be charged as a Company employee with alerting the Board to any perceived anomalies, inconsistencies or other unorthodox billing detail. Tr. at 101.

Dr. Rearden's broad concern about the proposed EEP related to the oversight and administration of the program is misplaced. First, they note that his criticism that the Program Administrator(s) are not accountable to anyone simply is not true. As explained by Mr. Kubert, the parties agreed (during the collaborative process that took place after the merger settlement) that both the Contract Administrator and the Program Administrator(s) would report to the Governance Board. In addition, the Program Evaluator would perform periodic audits on the performance of the programs against established performance criteria and also prepare annual reports for the Governance Board. Id. Again, the Program Evaluator would be independent of the gas companies, the Contract Administrator and the Program Administrator(s). Id. Moreover, the Staff liaison would be a non-voting member of the Board, thereby keeping the Commission apprised of all matters occurring with the Governance Board and its subcontractors. Id. at 6-7.

City-CUB note Dr. Rearden to be concerned with controlling overhead costs. On this point, the City and CUB agree. They assure that no party has an interest in spending limited energy efficiency funds on administrative costs. Mr. Kubert agreed with Dr. Rearden that there should be a binding constraint on the level of administrative costs and that there should be periodic reviews of the energy efficiency project overheads. ELPC Ex. 2.0 at 8. Peoples Gas-North Shore witness Rukis testified that she also agreed on these points. NS-PGL Ex. IR-3.0 at 5.

The GCI note Staff to claim that the proposed structure of the EEP does not "guarantee" "prudent expenditures." Staff Init. Br. at 202-03. Staff's argument focuses on the wrong question. The Commission should not ask whether every energy efficiency program that comes out of the EEP will be a perfect program that "guarantees" "prudent expenditures." Rather, the GCI maintain, the Commission should ask whether it is prudent to establish a program to design and implement energy efficiency programs. There is little doubt that the answer to that question is "yes."

First, Staff complains that no specific initiatives have been proposed, and the Companies cannot guarantee that the program will translate into prudent expenditures. Staff Brief at 203. However, utility ratemaking is by nature and law, a prospective process (*see, e.g.* Business and Professional People for the Public Interest v. Illinois Commerce Comm'n, 136 Ill.2d 192, 209, 555 N.E.2d 693 (1989) ("*BPI I*"); Citizens Utilities Co. v. Illinois Commerce Comm'n., 124 Ill. 2d 195, 207; 529 N.E.2d 510 (1988) that precludes the kind of before-the-fact micromanagement Staff seems to be demanding. The Commission's analysis of operating expenses, given the prospective nature of ratemaking, evaluates the kind and dollar amount of the expense being proposed, but for the most part rarely delves into the details of how the dollars are actually spent. For example, when the Commission evaluates a test year amount of office supplies, it typically does not investigate exactly how the budgeted amount is spent. Rather, the typical accounting analysis examines whether the expense itself is necessary for the provision of least-cost utility service and whether the amount requested is a reasonable, "normal" level based on historical experience. In doing so, the Commission intuitively recognizes that all businesses, gas utilities included, for example, require office supplies in order to provide utility service.

As Ms. Rukis made clear on cross-examination, the Commission would maintain authority over the EEP. The Commission has authority over the Companies' respective rates. Tr. at 104. Through reports provided to the Board, the Commission would have the ability to review the on-going progress of the EEP. Id.

Utilities' witness Rukis testified regarding the various kinds of programs that could be a part of the EEP funding approved in this docket. She stated that one of the first things that the Governance Board should accomplish is a market potential study which would further ensure the best and wisest use of available resources by identifying the opportunities to use the funds. Tr. at 97. That being said, she noted that the most common EEP is the technology rebate, which targets individual customers or businesses to purchase or install more efficient technology than currently being utilized with lower initial purchase or installation costs. Id. at 11, 14. These could be offered to both business and residential customers. Another possible program could take the form of a door-to-door direct install of free or low cost energy efficiency measures for homes and apartments. Id. at 12. Low income programs that target selected customer groups to provide assistance to replace old, inefficient furnaces and water heaters, or install weatherization measures to homes and apartments could also be a part of the EEPs provided. Id. Another possible program, shared savings financing, could be included wherein the customer pays for the cost of the energy efficiency installation through savings from the project with a low interest loan, often at a buy-down interest rate, according to Ms. Rukis. Id. She added that other EEPs could target new customers and new loads as part of an economic development package to ensure that any new load additions to the system are as efficient as possible. Id. Other components could include efforts at market transformation that include activities that develop and provide information on available energy efficiency options and energy saving best practices through education and outreach efforts. Id. at 13.

Both Utilities' witness Rukis and ELPC witness Kubert agreed that a $7.5 million funding level for the proposed EEPs will be sufficient to implement the kinds of programs and activities described above and achieve the benefits both witnesses concur would occur given implementation of the program. Ms. Rukis noted that the aforementioned market potential study she believes would be an appropriate first step in the program would enable the Governance Board to make the best use of the $7.5 million in funding provided by Peoples/North Shore customers. PGL Ex. IR-1.0 at 16; NS Ex. IR-1.0 at 16. The periodic reports prepared by the Program Evaluator and provided to the Board will also assist in assessing the effectiveness of the programs offered. Id.

Mr. Kubert concurred that the $7.5 million, while on the extreme low end of typical EEP funding in other Midwest states, would be a conservative amount with which to begin a program. ELPC Ex. 1.0 at 6. He noted that a lesser amount "would not allow the program to develop a comprehensive portfolio of services and incentives to impact a large number of customers." Id. Some program experience may be needed before any ramp-up to a higher funding level. Id. The Peoples/North Shore proposed EEP would be open to all ratepayers, with the actual number of participants being driven by program design, marketing and outreach. Id.

b) Proposal for Rider Recovery of EEP Costs

Proposed Rider EEP would allow the Companies to collect on a monthly basis the incremental costs to develop and implement energy efficiency measures. PGL Ex. VG-1.0 at 40; NS Ex. VG-1.0 3REV at 35. In the GCI's view, however, the proposed rider would recover costs that are not volatile and thus, under Illinois law, not appropriate for rider recovery.

According to GCI, the Finkl case dealt specifically with the very type of expenditure that Peoples Gas and North Shore would recover through Rider EEP. In that case, the court addressed the Commission's approval of Rider 22, which allowed ComEd to collect through a rider costs associated with investing in energy efficiency measures. Id. The court overturned the Commission, holding that the costs to be recovered under Rider 22 were no more volatile or beyond ComEd's control than many costs that are recovered through base rates. Id. at 327. The court concluded that such costs are not appropriately recovered through a rider and also considered that Rider 22 violated the single issue ratemaking rule. Id.

It is not clear to the GCI how the Companies can distinguish Rider EEP from Rider 22. They consider the evidence in this proceeding to be even less favorable for proposed Rider EEP than the evidence regarding Rider 22. In Finkl the court explained that Rider 22 was designed to recover certain categories of costs associated with providing energy efficiency programs. Id. Arguably, those costs could fluctuate or vary depending on the magnitude of energy efficiency projects that were designed and implemented. Here, the Companies are proposing to spend a predetermined amount ($7.5 million annually) to invest in energy efficiency projects. There is no room for deviation or fluctuations. Thus, the costs that would be recovered through Rider EEP are not appropriate for rider recovery.

In defending Rider EEP, the Companies offer two reasons why Rider EEP should be approved. First, the utilities assert that Peoples Gas previously recovered energy efficiency costs through its Rider 16. PGL-NS Init. Br. at 133. The Companies neglect to mention whether that rider pre-dated the Finkl decision and why that decision is not dispositive. Next, the Utilities state that "legislation has been offered that has been offered that may lead to a statewide energy efficiency initiative. The Companies add that if they fund programs pursuant to the statewide initiative, they would not want to burden their customers with funding multiple programs. Id. The Companies' argument is not persuasive in that, as it concedes, the legislation referenced has only proposed, it has not been enacted. Moreover, it is unclear to the GCI how the proposed legislation avoids the Finkl court's holding that energy efficiency programs are not appropriate for rider recovery.

In describing how the proposed tariff Rider EEP would be administered, Company witness Grace noted: "As budget dollars may not be fully expended as the program is building awareness in the initial program years, the Company proposes to carry over up to 75%, 50% and 25% of budget dollars into the second, third and fourth program years." PGL Ex. VG-1.0 at 40-41. In the GTCI's view, however, this carryover proposal does not justify approval of Rider EEP. As noted by Mr. Brosch, differences in actual disbursements for conservation programs relative to the $7.5 million of committed funding need not be addressed with a tariff rider. He stated that if the Commission is concerned with differences between recoveries from customers and actual expenditures by the utilities, a deferral accounting mechanism should be employed to track and reconcile differences between recovery (through base rates) and disbursements made by each utility for conservation programs. GCI Ex. MLB-1.0 at 72. Then, in future rate case proceedings, any unspent balance in the deferral account could be evaluated and recognized in the establishment of a revised ongoing recovery level within new base rates. Id. For example, if base rate recoveries total \$22.5 million after three years, but only \$17.5 million has been disbursed, the Commission might consider either directing larger annual disbursements for a period of time after year three or instead reduce the recovery rate embedded in a next rate case occurring at that time. If a full accounting for the economic value of base rate recovered conservation funding was desired, interest could be applied monthly to the cumulative over- or under-recovered balance in the regulatory asset or liability deferral account. Id.

The GCI note Staff to contend that deferral accounting of test year expenses is illegal under the BPI II decision. Staff Init. Br. at 221. If the Commission agrees with Staff, the GCI understand that this would require base rate treatment of the expense.

The GCI observe the Companies to propose that, if the Commission rejects rider treatment, to account for the EEP expenses through deferral accounting treatment "so long as the deferred account process was annual, as opposed to between rate cases." PGL-NS Brief at 135. The GCI argue that this approach should be rejected as unnecessarily complex and time-consuming. Mr. Brosch noted that there would be administrative cost savings to the Utilities and the Commission Staff by avoiding the creation of an additional tariff rider with periodic filings to review and reconciliation adjustments to calculate and apply. The Commission could still keep apprised of the relative success of the EEP through the filings provided by the Program Evaluator and through the Staff liaison who would sit as a non-voting member of the Governance Board. Of course, a full review of program activities and costs would also occur in periodic general rates cases where all parties with an interest in such matters can readily participate. Id.

The GCI would have the Companies' request to recover EEP costs through a Rider EEP be rejected for several reasons. First and foremost, the \$7.5 million in EEP costs do not satisfy the legal criteria for permissible rider treatment. GCI witness Brosch testified that neither the size nor anticipated volatility of conservation funding expense justify a special tariff Rider for this element of the Companies' revenue requirement. He pointed out that the EEP funding obligation that would be addressed by proposed Rider EEP is a fixed \$7.5 million annual amount across both utilities, an amount that is not expected to change in the foreseeable future. GCI Ex. MLB-1.0 at 72. And, Mr. Brosch stated that such a fixed expense can and should be included in the basic revenue requirement in these consolidated dockets to "ensure that the defined level of funding is made available on an ongoing basis," as suggested by Mr. Feingold. Id.

5. Commission Analysis and Conclusion

The Merits of EEP

As a condition to the merger approved in In re WPS Resources, Inc., Docket No. 06-0540, the Commission required the Utilities to propose a new ratepayer funded energy efficiency program of not less than $7.5 million per year. The Utilities fulfilled that condition by proposing Rider EEP. The Commission is highly pleased to consider and accept the EEP and it commends the concerted efforts and good work that brought it to the table.

Energy efficiency programs are socially desirable. In the recent Nicor rate case proceeding, the Commission recognized the importance and critical necessity of using energy efficiency plans as strategic tools to protect Illinois consumers and reduce their energy costs. Nicor, Order at 193, Docket 04-0779 (September 20, 2005).

As described on record, the proposed governance structure for the program should ensure independence from the Utilities and will likely result in representation of all or substantially all relevant interests. Further, the program's anticipated focus on rebates and other incentives supporting energy efficient technologies and gas saving techniques is appropriate and may encourage greater utilization of such technologies and techniques than high prices alone.

The Commission rejects Staff's arguments that the program is necessarily inequitable and inefficient. With proper independent governance and oversight, and with the selection of appropriate, cost-effective efficiency measures, the Commission believes that the proposed programs will make a significant positive contribution to the benefit of all ratepayers. Accordingly, the Commission orders the Utilities to implement the energy efficiency program as proposed. We find the structure to be fair and reasonable. The Commission additionally finds reasonable the $6.4 million that is allocated to Peoples Gas and the $1.1 million that is allocated to North Shore, as well as the portion of each amount that would be available for low income programs. And, the Commission considers Staff witness Rearden's proposal to cap administrative costs at 5% to be both reasonable and appropriate in these premises. Thus, Staff's recommendation in this instance is approved.

Rider Treatment of EEP

The Commission further considers and finds that Rider EEP costs merit rider treatment. The parties objecting to rider treatment have argued that because the Utilities have agreed to spend $7.5 million, i.e., a fixed amount, that the Utilities cannot utilize a rider to recover these expenses because since the amount is known, it cannot possibly be "unexpected, volatile or fluctuating." We disagree. The parties prominently rely on the Finkl case for this proposition. Later decisions, however, have held that nothing in Finkl limits the use of a rider to only those instances where costs are unexpected, volatile or fluctuating City of Chicago v. Illinois Commerce Commission, 281 Ill. App.3d 617 (1st Dist. 1996).

More important in our decision to adopt the Utilities' rider treatment is that the manner in which this money will be spent is far beyond the Utilities' control. A. Finkl, 250 Ill.App.3d at 327. As set out on record, the Governance Board's voting procedure ensures the independence of the board from the Utilities. Because the Utilities do not "control" how much of the $7.5 million will be spent each year, it is not appropriate for the program costs to be included in rate base. The Commission further finds that Rider EEP is a reasonable means by which the Utilities may recover the EEP costs that they incur as a result of the programs and benefit ratepayers in that they will only be charged the amount actually spent.

Also, we believe the costs are appropriately included in rate base when savings can be expected. This balancing, however, will not occur for the energy efficiency costs. We expect that any money the EEP spends on energy efficiency will decrease the Utilities revenues as customers will use less gas. Indeed, that is the whole point and objective of the EEP. Thus, in every way, these are unique costs and warrant rider treatment.

Further, knowing that the energy efficiency program will be administered by an independent board lessens our concern over the costs of administrating Rider EEP. In other words, and given the composition of this body, we expect that that any reconciliation proceedings would likely not be litigious because most, if not all interested parties, would have had a say in the efficiency program spending process.

Although we do not adopt Staff's position, several of its proposals bear consideration. Staff witness Hathhorn recommends, if the Commission adopts the Rider EEP, that: 1) an annual reconciliation procedure should be established; 2) an internal audit should be conducted; and, 3) the monthly tariff filing date should be changed. The Utilities have agreed to these changes and we adopt them as well. The annual reconciliation will ensure that ratepayers are only charged for the actual costs of the energy efficiency program prudently incurred. This is fair and just.

D. Rider UBA

The Utilities also request approval for Rider UBA to recover the gas cost-related portion of their uncollectible customer bills (also called bad debt expense). They describe Rider UBA as a monthly volumetric adjustment applied to gas the Utilities supply to customers (except in Service Classes 5 and 7). PGL-NS Init. Br. at 142. The adjustment would be computed by multiplying the uncollectible expense percentage approved in these rate proceedings by the forecasted Gas Charge revenues arising from the application of Rider 2 to the following month, then dividing by the applicable volumes for the same month, yielding the effective adjustment. Id. Any differences between billed revenues and uncollectible expenses under the Rider would be reconciled annually and amortized over a 10-month span, with the resulting adjustment added to customers' bills during that period. Id. Customers would also be responsible for (or receive the benefit of) interest on over- and under-recovered amounts. AG Init. Br. at 121. "Then, because the annual reconciliation amounts are also subject to over or under-recovery, a further true-up is required." Id.

Additionally, the Utilities would file monthly prospective reports with the Commission, detailing expected activity under Rider UBA. They would also annually audit rider performance, and file a report in February to determine the earlier discussed reconciliation adjustment. PGL Ex. VG-1.0 at 44-45; NS Ex. VG-1.0 at 39- 40. Rider UBA will only pertain to the gas cost portion of the Utilities' bad debt expense. Non-gas cost uncollectible expense would be recovered in base rates.

The test year uncollectible gas cost expenses to be recovered through Rider UBA are $26.7 million and $1.5 million dollars for Peoples Gas and North Shore, respectively. PGL Ex. VG-1.0 at 45; NS Ex. VG-1.0 at 41. If the Commission does not approve Rider UBA, the Utilities would continue to include and recover gas cost-related bad debt through its base rates.

The Utilities maintain that "uncollectible accounts are a rising and recurring business expense" that is "uncontrollable, highly variable and unpredictable, with resulting negative financial consequences." PGL-NS Init. Br. at 141-42. They also assert that "the level of uncollectible expense on the Utilities' system is substantially greater than has historically been the case." Id. at 143. The Utilities contend further that these circumstances are the result of economic conditions…the level of gas commodity and delivery prices and the demographics of the Utilities' service territories. Id. at 141. In the Utilities' view, Rider UBA will provide the antidote to these problems by allowing steady bad debt recovery between rate cases. They stress that utility regulators in ten states have approved "bad debt ratemaking mechanisms" for gas utilities. PGL-NS Ex. RAF-1.0 at 41.

The Utilities particularly emphasize that gas costs are themselves recovered through a rider, not through base rates, precisely because of their volatility. Accordingly, and given their conviction that uncollectibles correlate with gas prices, the Utilities conclude that gas price-related bad debt should be similarly recovered via rider. PGL-NS Rep. Br. at 120, n. 32. Additionally, the Utilities support Rider UBA with the same legal arguments (concerning appropriate circumstances for rider recovery) that they have presented on behalf of their other proposed riders in these dockets.

In return, the AG, Staff and City-CUB reprise the legal arguments they presented against the Utilities' other riders. Again relying on Finkl, the AG states that "to qualify for rider treatment, expenses must be unexpected, volatile or fluctuating and significant in nature." AG Init. Br. at 114. The AG argues that Rider UBA does not satisfy the first two of those criteria because "the magnitude and volatility of these expenses do not rise to the level or degree of purchased gas costs." Id.

Further, the AG avers, gas cost-related bad debt expenses are not "substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases." Id. Staff echoes this argument, noting that the Utilities were able to earn their authorized rates of return when uncollectibles rose, as in 2001, when, despite a sharp rise in bad debt, Peoples Gas and North Shore earned returns on common equity of 11.14% and 12.30%. Staff Rep. Br. at 90. "Thus, if Rider UBA had been in effect during this time, both utilities would have received additional revenue boosts despite earning at or above their authorized returns." Id. at 91. Similarly, City-CUB stresses that if Rider UBA had been in place from 2-002-2006, Peoples Gas "would have collected an approximately additional $21 in pre-tax operating income and [North Shore] would have received $2.9 million." City-CUB Init. Br. at 92.

Staff also puts particular emphasis on our rejection of a proposed rider in Nicor. In that proceeding, we said that "costs, such as uncollectibles, which are a normal cost of the provision of service, do not warrant special recovery through a rider. Nicor has not met its burden of showing that these costs are of a nature that should be recovered through a rider rather than through base rates." Nicor, at 181, *quoted in* Staff Rep. Br. at 86.

Commission Conclusions

As we have stated elsewhere in this Order, rider recovery is allowed at the Commission's sound discretion. The judicial precedents cited by the parties establish no right to a rider. In a rate case, the question is whether the pertinent expenses are optimally recovered between rate proceedings through a rider, apart from the established test year cost and revenue balancing process. In prior cases, the prerequisites for rider recovery have been that the relevant costs are volatile, unpredictable and independent of utility control. Again, these are not all-or-nothing factors. Thus, for example, a modicum of cost volatility will not automatically warrant rider recovery, and a modicum of cost consistency will not necessarily preclude rider treatment.

The Utilities' principle argument on behalf of Rider VBA is the "undeniable" relationship between gas prices and bad debt[44]. This relationship provides the platform from which the Utilities would propel bad debt from rate case expense recovery to continuous rider recovery. That is, the Utilities' argument goes, because gas costs have already demonstrated the requisite characteristics for rider recovery, gas cost-related uncollectibles, which ostensibly follow gas prices, also warrant rider recovery. The Commission agrees with the proposition that there is some correlation between substantial increases[45] in gas bills and the ability of some consumers to pay those bills. However, it is one thing to say that bad debt fluctuates when gas bills fluctuate; it is another to say that bad debt moves just like gas prices (and, therefore, require the same recovery mechanism).

The Utilities' evidence does not demonstrate the degree of correlation they assert. When Peoples Gas's gas prices (PGL Ex. LTB-1.1) as well as its gas charges to customers (PGL Ex. LTB-1.2) rose dramatically in early 2001, so, too, did gas-related bad debt. PGL Ex. LTB-1.5. But when gas prices and charges dropped thereafter (and well into 2002), bad debt actually continued upward to its highest level. Id. In 2003, when gas prices jumped substantially above the 2002 level, along with an increase in gas charges to customers, bad debt dipped slightly, and the gas-related proportion of bad debt remained essentially constant. Id. Bad debt then fell during 2004 and stayed

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[44] Although the Utilities mention "economic conditions" and the "demographics" of their service territories as additional causes of the unpredictability, variability and magnitude of bad debt, they offer scant evidence on these matters, PGL Ex. LTB-1.0 at 16, and do not at all demonstrate their purported connection to the Utilities' uncollectible gas cost-related expenses.

[45] Although Rider UBA also accommodates substantial uncollectibles *decreases*, the real dispute here (and the real problem, as the Utilities see it) concerns increases in bad debt. We do not presume that an entity would request a rider to avert *over*-collection of expenses.

constant in 2005 (although the proportion of gas-related bad debt increased moderately), while gas prices and charges trended sharply upward[46].

For North Shore, gas prices (NS Ex. LTB-1.1) and gas charges to customers (NS Ex. LTB-1.2) also rose steeply in early 2001, accompanied by gas-related uncollectibles. NS Ex. LTB-1.4. When gas prices and charges slumped after that (and well into 2002), North Shore's gas-related bad debt, unlike Peoples Gas's, did decrease, but not at the rate of gas prices and charges, which fell back to pre-2001 levels. Id. When gas prices and charges rose again in 2003,North Shore's bad debt spiked well beyond 2001 uncollectibles, although gas prices, and especially gas charges, did not attain the 2001 level. Id. North Shore's uncollectibles dropped in 2004, along with gas prices and charges, but in contrast to Peoples Gas's bad debt, shot up again in 2005 as gas prices and charges increased again. Id. Thus, North Shore's customer delinquencies showed a closer correlation to gas prices and charges than Peoples Gas's, but North Shore and Peoples Gas uncollectibles did not move like each other, nor did either consistently move with gas prices and charges.

The foregoing dynamics are consistent with what the Commission understands about customer behavior, at least with respect to Peoples Gas[47]. When gas bills rise, some customers will suppress their usage or install premises insulation or more efficient appliances (or turn to alternate energy sources). PGL Ex. LTB 1.0 at 11 & 16. Some will not suppress usage, but will nevertheless pay gas bills with funds intended for other purposes. Some will borrow to avoid disconnection or adverse impact to their credit. Thus, while the Utilities, under their statutory and contractual obligations, must invariably purchase gas and pass it through their purchase gas adjsutments, customers will not invariably delay or default on their gas bills in like fashion.

The evidence above additionally shows that customers adjust over time to higher bills (perhaps by resorting to the measures described above, or perhaps due to other economic factors in the service territory). Looking again at PGL Ex. LTB 1.5 (PGL-NS Rep. Br. at 120) we see that the proportion of gas-related bad debt to overall bad debt essentially holds steady, both year-to-year and over the four-year period, as does the absolute amount of gas-related bad debt. This is so despite the movement in gas prices and charges discussed above. PGL Ex. LTB-1.1 & 1.2.

Moreover, even when customers endeavor to delay or avoid paying increasing amounts due, the Utilities act to mitigate the potential revenue reduction. According to PGL-NS witness, Kallas, PGL has "been able to control its uncollectible expenses" for fiscal years 1997 through 2006 by requiring deposits from high risk customers, customer credit reporting, automated review for outstanding balances on the previous accounts of new customers, automated collections calls and disconnection prioritized by

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[46] The price, gas charge and uncollectible movements described here are also reflected in PGL Ex. LK-1.2.

[47] The disparate aggregate behavior by, respectively, Peoples Gas and NS customers is not explained by the record. Because Peoples Gas has much a larger customer base (850,000 versus 158,000, PGL-NS Ex. LTB-1.0) and far higher total uncollectibles (a high of over $40 million at Peoples Gas compared to over $1.6 million for NS, PGL Ex. LTB-1.5; NS Ex. LTB-1.4), the relative impact of a few accounts may be greater for NS. Or economic differences between the service territories may be important factors.

the delinquent customer's behavior score. PGL Ex. LK-1.0 at 17. North Shore uses the same collection enhancements (NS Ex. LK-1.0 at 17) and "uncollectible expense as a percentage of applicable revenues for the test year and three preceding years…has been fairly constant over that time period," *id*. at 16, although uncollectibles rose substantially on a dollar basis in alternating years during that span. NS Ex. LK-1.2.

The salient point here is not that gas price movements have no effect on uncollectibles (they do have some effect), but that the two do not move so closely together to automatically grant rider treatment to the latter because the former has rider treatment. Moreover, through enhanced credit and collection measures, the Utilities have some appreciable capacity to constrain uncollectibles, even when gas prices move upward. Restating this in the terms of the judicial precedents and prior Commission Orders discussed previously, gas-cost related uncollectibles do not demonstrate the degree of volatility or independence from utility control that caused us to allow recovery of gas costs through riders.

Even when we consider gas-cost related bad debt on its own (that is, apart from the association of that bad debt with the Utilities' gas costs), we still do not find sufficient basis for rider recovery. The parties have briskly debated the relationship between uncollectibles and other operating expenses, with Staff and intervenors showing that uncollectibles are less volatile than other operating expenses in absolute dollars, while the Utilities show that uncollectibles are more volatile on a percentage basis[48]. The AG aptly points out that the smaller size of uncollectibles makes larger percentage movements more likely. AG Rep. Br. at 80. Additionally, on a year-over-year basis, Peoples Gas's gas cost-related bad debt has been reasonably steady (with a moderate decline) from 2001 through 2005. PGL Ex. LTB-1.5.

While North Shore has shown greater year-to-year movement in uncollectibles, Utilities' witness Kallas acknowledges that "the uncollectible provision rate (expressed both as the accrual rate as well as the effective rate (after adjustment) has operated within a fairly tight range." NS Ex. LK-1.0 at 16-17.

The Commission finds that the Utilities' fluctuations in uncollectibles are not large or frequent enough, and the incidence of bad debt is not independent enough from the Utilities' debt management practices. Again, this is not an all-or-nothing analysis. There is some fluctuation to the Utilities' uncollectibles, and there is consumer behavior beyond the Utilities' influence. But variability is a characteristic of virtually every utility cost. Despite the most perspicacious predictions, future events take their own course. Yet virtually all of those costs are still held within the test year process. Indeed, all that our rate-setting offers is an opportunity to earn a fair return, not a fixed future dollar amount.

The appropriate issue, therefore, is whether gas cost-related bad debt is unique enough to warrant an assured and continuous rider recovery of actual expense. Based on the evidence here, we conclude that it is not. The pertinent uncollectibles will be

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[48] The relevant evidence appears at PGL-NS RAF-2.2, Staff Ex. 8.0 at 26 and GCI MLB-4.0 at 22-23. We note that this evidence deals with uncollectibles generally, and not gas cost-related bad debt specifically.

adequately addressed in base rates. Elsewhere in this Order, we approve significant increases, over existing rates, in gas cost-related bad debt expense – for Peoples Gas, $26.7 million, PGL Ex. VG-1.0 at 45, (versus approximately $14.5 million), and for North Shore, $1.5 million, NS EX. VG-1.0 at 41, (versus approximately $500,000). These amounts exceed gas cost-related uncollectibles in every year from 1996 through 2005, and are essentially equal to 2006 bad debt. PGL Ex. LTB-1.5; NS Ex. LTB-1.4; PGL-NS Ex's LK-1.2. That is sufficient.

Furthermore, looking forward, the evidence shows that now-existing exogenous factors described by the Utilities will tend to moderate the amount or fluctuations in the Utilities' future gas-related uncollectibles. In support of revising weather normalization methodology, the Utilities have asserted that global warming is reducing HDDs and, thereby, gas consumption. PGL Ex. LTB-1.0 at 10; NS Ex. LTB-1.0 at 10. Similarly, to justify their requested Rider VBA, the Utilities show that efficiencies and insulation, along with higher gas bills, are reducing customer usage. PGL Ex. LTB-1.0 at 11; NS Ex. LTB-1.0 at 14. Insofar as these factors constrain usage, they are also likely to limit gas-related bad debt.

Accordingly, as we did in Nicor, we reject the request to recover uncollectibles through a rider. We continue to believe that "Commodity-related uncollectibles expense should not be split from other uncollectibles expense… costs, such as uncollectibles, which are a normal cost of the provision of service, do not warrant special recovery through a rider…The gas cost portion of Nicor's uncollectibles is presently being recovered through base rates, and should continue to be recovered through base rates." Nicor, at 181.

The Commission notes that there is a consensus that the CFY customers should not be required to pay for the bad debt cost of sales customers associated with their gas costs. The Commission therefore approves the reduction in "Choices For You" charges calculated by Utilities' witness Grace. PGL-NS Ex. VG- 2.0.

E. Deferred Accounting Alternative to Certain Rider Requests

In the event the Commission rejects one or more of Riders VBA, UBA or EEP, the Utilities propose, as an alternative, to track the underlying revenues and costs in deferral accounts, for later refund or adjustment to base rates as determined on an annual basis. PGL-NS Ex. VG-2.0 at 50-51. The Utilities assert that this would not violate test year principles but would, instead, allow them to go ahead with these expenditures. Given that the Commission has approved Rider VBA and Rider EEP, but rejected Rider UBA, the Utilities' fall-back proposal would apply to the latter rider.

With respect to Rider UBA, the Utilities' argue that "normalization of uncollectible expenses is hardly unprecedented. PGL-NS Rep. Br. at 127. The Commission does not agree that the future recovery requested here is a matter of "normalization." Nor is this a matter of completing a previously approved amortization. Uncollectibles are operating expenses and, as Staff states, "recovery of operating expenses outside of the test year violates test year principles" articulated in BPI II. Staff Init. Br. at 223. Furthermore, even if the Commission could approve the requested deferred accounting of uncollectibles, we would not exercise our discretion to do so. We believe that a reasonable quantification of the Utilities' gas-related uncollectibles has been incorporated in the rates approved by this Order. The Commission does not perceive that the Utilities' actual uncollectibles will differ appreciably from that quantification.

VIII. COST OF SERVICE

A. Overview

A cost of service study aims to find the various costs of serving all of a utility's customers and to allocate these costs to individual customer classes. Here, the Utilities have presented the Embedded Costs of Service Studies ("ECOSS") sponsored by their witness, Ronald Amen. The ECOSS for Peoples Gas is set forth in PGL Exs. RJA-1.1, 1.2 REV. - 1.4, 1.7 REV. - 1.8, 1.9 REV., and 1.10 REV and that for North Shore is set forth in NS Exs. RJA-1.1, 1.2 REV. - 1.4, 1.7 REV. - 1.8, 1.9 REV., and 1.10 REV.

The Utilities were the only parties who submitted ECOSS in these proceedings. Staff witness Luth made certain proposed adjustments to the ECOSS using the Utilities' ECOSS models. In addition, Staff the AG and City-CUB made criticisms of selective aspects of the ECOSS, but none of those parties appear to have taken issue with the Utilities' broader ECOSS methodology or approach.

In section B -1 below, addresses all of the items not in dispute.

In sections B -2 below, we examine the matters being contested. The contested ECOSS issues in this proceeding are:

(a) whether common system distribution costs should be allocated on the basis of the Coincident Peak ("CP") method proposed by the Utilities versus the Averages and Peak ("A&P") method favored by Staff;

(b) whether Account No. 904 should be classified as customer costs as proposed by the Utilities;

(c) whether S.C. No. 1 should be bifurcated into heating and non-heating customers, as proposed by the Utilities but opposed by GCI;

(d) whether Account No. 385 costs should be directly assigned, as proposed by GCI but as opposed by the Utilities;

(e) whether differentiating rates of return by class, opposed by the Utilities but proposed by City-CUB, is reasonable; and,

(f) whether the EPEC methodology proposed by the Utilities for allocating overall revenue requirement among the various customer classes is appropriate.

B. Embedded Cost of Service Study

1. Uncontested Issues

a) Functionalization of Intangible Plant Account Nos. 303.1 and 303.2

The Utilities' proposal functionalized Accounts 303.1 and 303.2 costs solely as customer - related costs. In his testimony, Staff witness Luth proposed that the Utilities functionalize those Accounts according to their relative weight of depreciable Production, Storage, Transmission, Distribution and Customer Accounts Plant. Staff Ex. 7.0 at 4. The Utilities have accepted Mr. Luth's proposal which recommends that costs in Account Nos. 303.1 and 303.2 should not be based solely on customer account costs, but should be functionalized as Customer Accounts, Distribution related and the remaining amounts spread ratably among the functions to reflect the general and administrative uses of the remaining software and systems applications. NS-PGL Ex. RJA-2.0 at 11; NS-PGL Ex. RJA-2.3.

The Commission finds Staff's final proposal, that the Utilities functionalize Accounts 303.1 and 303.2 costs as customer accounts and distribution-related, with remaining amounts to be spread ratably among the functions to reflect the general and administrative uses of the remaining software and systems applications, to be unopposed by any party. And, it is reasonable and appropriate. The Commission, therefore, approves this proposal.

b) Classification of Distribution Plant Account No. 375

The Utilities proposed the allocation of Account No. 375, Distribution Plant - Structures Improvements, as a combination of demand and customer costs. Staff witness Luth recommended that Account No. 375 be classified entirely as a demand - related cost rather than a combination of other costs, including customer costs. Staff Ex. 7.0 at 4. The Utilities have accepted the proposal of Staff witness Luth and agreed to classify Account No. 375 solely as a demand - related cost. NS-PGL RJA-2.0 at 12; NS-PGL RJA-2.3 and NS-PGL RJA-2.4.

The Commission finds Staff's final proposal, i.e., that the Utilities classify Account No. 375 entirely as a demand-related cost, which is not opposed by any party, to be reasonable and appropriate. The Commission, therefore, approves this proposal.

2. Contested Issues

a) Coincident Peak Versus Average and Peak Allocation Methods

(1) Utilities

The Utilities' preferred methodology for the allocation of system demand costs is the Coincident Peak ("CP") methodology, based on the Peak Demand Design days of their respective systems, which they believe is most appropriate in view of the specific characteristics of their respective systems and the principle of allocating costs to customers on a causal basis. For demonstrative purposes, two other options were considered by the Utilities in their ECOSS: (1) a CP method which classifies a portion of the distribution mains as customer-related costs, and (2) an Average and Peak ("A&P") approach.

Because the Utilities' investment in their distribution systems is sized to meet peak demands so that they have the ability to meet their respective service obligations throughout the year, the Utilities believe the CP method produces the most conceptually sound and balanced outcome. A Peak Demand Design Day methodology, they explain, directly measures the gas demand requirements of the Utilities' firm service customers who create the need for the Utilities to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis. PGL Ex. RJA-1.0 at 21, NS Ex. RJA-1.0 at 21. Further, the use of this methodology to allocate system demand costs is the most reasonable approach because it is related to the actual system as it was built to serve customers' specific needs. Hence, the Utilities assert, this ECOSS methodology is the best way to capture the true cost causative factors of the Utilities' operations. Finally, Utilities' witness Amen points out that this methodology is almost always utilized when designing a gas distribution system to accommodate the gas demand requirements of customers served by the system. PGL-NS Ex. RJA-1.0 at 19.

According to the Utilities, neither Mr. Luth on behalf of the Staff, nor Mr. Thomas on behalf of CUB-City, sufficiently explain why the A&P method is a more appropriate methodology for allocation of the Utilities' system demand costs. Neither witness explains how the A&P method, particularly its focus on average usage over peak usage, accurately reflects or relates to how the Utilities' systems were built. Instead, Staff provides conclusory statements that a "significant amount" of distribution costs are not affected by peak demand considerations, while Mr. Luth's support for A&P is based on his generic belief that average deliveries are a relevant consideration.

In the Utilities view, the proponents of the A&P methodology failed to address how a utility's system, if sized only to accommodate average gas demands, would be able to meet peak system demands, or why under the circumstances the Commission should deviate from its (and the industry's) norm of using the CP methodology. In the absence of detailed and persuasive analyses indicating why the A&P methodology should be adopted for either or both of their systems, the Utilities assert that the CP method should be approved because it has been supported with sound reasoning and analysis.

While the Utilities maintain that the CP method of cost allocation be applied, they observe that Staff, AG and City-CUB oppose its utilization and recommend that an Average and Peak ("A&P") method be used instead. Essentially, the parties criticized the CP method because they believe that the CP method incorrectly assumes that system costs are driven by peak demands on the system. These parties believe that a "significant amount" of distribution costs are not affected by peak demand considerations. Staff Init. Br. at 228. The Utilities observe Staff witness Luth to recommend the A&P method based upon his belief that distribution costs are affected by, but not entirely dependent on, peak demand and that some consideration be given to average deliveries. *See* Staff Ex. 7.0 at 13.

The Utilities believe that the CP method is the soundest approach to allocation of system costs. The CP method most closely matches the principle that cost causation should follow cost responsibility. The distribution system was built to serve the peak demands of the system. Thus, a customer's peak demand on the system corresponds to the costs that have been incurred to install that capacity. Since the customer's demand on the system prompted the installation of facilities to meet that demand, it stands to reason that customers should be allocated costs in a manner that recognizes their call on the system.

The Utilities point out that the CP allocation method requires each customer to pay for the capacity that it is entitled to call upon whenever its usage necessitates it, whether on one day a year or every day of the year. To recognize average usage, as does the A&P method, the Utilities explain, is to incorporate non-cost considerations into the allocation process. This, the contend, results in diminishing cost causation responsibility and transferring cost responsibility from those customers who cause it to those customers who really bear less responsibility for the costs having been incurred.

The Utilities observe that the Commission had approved the CP method in the Utilities' last two rate cases, In re Peoples Gas Light and Coke Co., Dockets 91-0007 and 91-0586; in the two Peoples Gas rate cases prior to those, the A&P method was adopted. There is thus no settled practice in regards to the method for allocation of system costs. The trend toward promoting more direct responsibility for costs and the imperative of moving customers toward full cost responsibility as followed in the Utilities, rate design proposals, require that the same concept be applied in the system cost allocation process. The Utilities therefore urge the Commission to apply the CP method of cost allocation to the system costs in these proceedings. This is contrary to the AG's assertion that the A&P method establishes "clear precedent," AG Init. Br. at 136, The Commission has also shown a preference for the CP method and the Utilities believe that adoption of the CP method would be more consistent with the ratemaking policies employed most contemporaneously.

(2) Staff

The flaw in CP allocation, according to Staff, is its assumption that all distribution system costs are caused by additional installed capacity necessitated by natural gas deliveries on the date that natural gas volumes are greatest. Yet, as the Utilities' own cost of service witness Amen explained, not all distribution system costs vary according to increased capacity. NS Ex. RJA-1.0 at 25-26; PGL Ex. RJA-1.0, at 25. Staff contends that a significant amount of distribution system costs are not affected by the size of the distribution main, as expressed by the factor "b" in the North Shore and Peoples Gas cost equations and explanation provided by Mr. Amen. Staff rejects Mr. Amen's reason for introducing the cost equation, which is an attempt to show that distribution costs could be allocated, in part, according to customer count regardless of customer size, so that a Peoples Gas residential SC 1N customer with 9 therms of monthly usage would be allocated the same costs as a Large Volume Demand SC 4 customer with 71,933 therms of monthly usage residential SC 1N customer with 9 therms of monthly usage. Paradoxically, the cost equation provided by Mr. Amen demonstrates the inequity of fully allocating distribution system costs according to CP, even though the Utilities proposed rates based upon CP.

Staff witness Luth recommends an A&P allocation of distribution system costs. In his view, A&P is superior to CP because A&P recognizes that distribution system costs are affected by, but are not entirely dependent upon, increased installed capacity. Staff Ex. 7.0 at 13, 15. In addition to the share of deliveries on the peak date, A&P also takes into consideration average daily deliveries in allocating distribution system costs. Id. at 14. As a result, the use of the distribution system on the 364 days of the year in addition to the peak date is also considered when allocating the costs of the distribution system under A&P. Since it makes sense that distribution system costs are not entirely based upon the size of the distribution system, as demonstrated by the Utilities' witness Amen's testimony addressing the makeup of gas distribution system costs, the A&P allocation of a portion of distribution system costs according to average use throughout the year is reasonable and fair.

Staff suggests that A&P may suffer from a misnomer. A&P could probably be re-named to Peak and Average so that it is not implied that average deliveries have greater influence on the allocation of distribution system costs than the share of deliveries on the peak date. Tr. at 1482. For Peoples Gas and North Shore, A&P is weighted approximately 75 percent according to coincident peak and 25 percent according to average daily deliveries. Staff Ex. 7.0 at 14. It is clear, therefore, from the weighting of coincident peak and average daily deliveries in the A&P formula, that the effect of costs from increased installed capacity is a significant factor in an A&P allocation in addition to average daily deliveries. Thus, A&P is a more reasonable balance and measure of allocating the costs of installed mains which are unaffected by increased capacity, and costs that are affected by increased capacity, as depicted in the equations provided by Peoples Gas and North Shore witness Amen.

Over the past decade, Staff observes, the Commission has consistently found that A&P allocation of distribution system costs is preferable to a CP allocation, Tr. at 1484-85 (Luth), including: the most recent North Shore and Peoples Gas Orders (North Shore, Docket No. 95-0031, Order at 33-36 (November 8, 1995); Peoples Gas, Docket No. 95-0032 at 41-42)); Nicor Gas' most recent rate case order (Docket No. 04-0779, Order (September 20, 2005)), Illinois Power's 2004 request for increase in gas rates (Docket No. 04-0476, Order at 64-66 (May 17, 2005)), CIPS' and UE's 2002 request for increase in gas rates (Docket Nos. 03-0008 and 03-0009, Order at 98 (October 22, 2003)), Nicor Gas' 1995 request for increase in gas rates (Docket No. 95-0219, Order (April 3, 1996)); and CILCO's 1994 request for increase in gas rates (Docket No. 94-0040, Order (December 12, 1994)). For the same reasons that the Commission has found that A&P allocation is preferable to a CP allocation over the past decade, Tr. at 1484-85 (Luth), the Commission should conclude that distribution system costs should be allocated according to A&P rather than CP so that rates are based upon how the distribution system is used throughout the year, and not solely on the date of highest deliveries.

In concluding that A&P is a more appropriate method of allocating distribution system costs than CP, Staff observes that previous Commission Orders have focused on factors other than capacity, such as safety, reliability, and equipment replacement as being significant elements in the cost of the distribution system. In fact, the Orders in the previous North Shore and Peoples Gas rate proceedings recognized those concerns in the development of the distribution system as factors that are not peak-related, and found that transmission and distribution costs should be allocated according to Staff's A&P allocation factor. Docket No. 95-0031, Order at 36-37, and Docket No. 95-0032, Order at 42-43. Staff notes that the Commission's adoption of an A&P allocation methodology has been upheld on appeal. *See* Abbott Lab. v. Illinois Commerce Comm'n., 289 Ill. App. 3d 705, 716-717 (1st Dist. 1997) (Commission's adoption of A&P is supported by substantial evidence). Thus, the Commission should once again reject the Utilities' proposed CP allocation factor because it fails to address costs that are not peak-related, and accept Staff's A&P allocation factor which recognizes and reasonably allocates transmission and distribution costs that are not only peak-related, but also affected by concerns other than design day peak.

(3) CUB-CITY

City-CUB also recommend that the Commission employ the A&P methodology. CUB-City Ex. 1.0 at 74-75. According to City-CUB, the Utilities' recommendation to use the CP method deviates from the Commission's approach in "virtually every natural gas delivery service rate case in the past ten years." Id. at 74. In this regard, they note the Commission to have concluded in the recent Nicor rate case , i.e., Docket No. 04-0779, that not all costs of the natural gas distribution system "are directly related to peak demand," and the A&P method, therefore, is a more appropriate means of allocating demand-related costs. Staff Ex. 7.0 at 13 (*citing* Nicor at 102). That principle applies equally to the Utilities. Indeed, their witness Ronald Amen conceded that the Commission had adopted the A&P methodology in Peoples Gas's previous rate case. PGL Ex. RJA-1.0 at 17.

Despite the Commission's longstanding policy of applying the A&P allocation method, the Utilities contend that the CP method best reflects cost causation on the utilities' systems. In particular, Mr. Amen asserted in his Rebuttal Testimony that, based on "the underlying engineering and cost characteristics of the distribution system," demand-related costs are incurred entirely to meet peak demands. NS-PGL Ex. RJA-2.0 at 7. In his Direct Testimony, Mr. Amen maintained that this is so because

> a peak demand design criterion is always utilized when designing a gas distribution system to accommodate the gas demand requirements of the customers served from that system, whether the investment is driven by the need to replace aging and deteriorating pipelines or for the purpose of expanding the transmission or distribution capacity to serve growing demand on the system. As Peoples Gas witness Mr. Doerk discusses (Peoples Gas Ex. ED-1.0), a utility's gas system sized only to accommodate average gas demands would be unable to accommodate system peak demands. That is, by sizing plant investment for peak period demands, the utility is assured to satisfy its service obligation throughout the year. As such, cost causation with respect to demand related costs is unrelated to average demand characteristics.

PGL Ex. RJA-1.0 at 19.

Despite Mr. Amen's professed understanding of the Utilities' operations, *see* PGL Ex. RJA-1.0 at 21, his testimony regarding the operational basis for the CP method was contradicted at the evidentiary hearing by Peoples Gas and North Shore Vice-President, Gas Operations, Edward Doerk. Mr. Doerk is the corporate officer (for both Utilities) responsible for "all facets of gas distribution utility operations including maintenance, construction, engineering, customer service, and technical training." PGL Ex. ED-1.0 at 3.

City-CUB point out that, in testimony at hearing, Mr. Doerk acknowledged that the Utilities' demand costs are not solely related to serving peak demands -- the essential premise of their objection to the Utilities' proposal to rely entirely on the system peak for allocating distribution plant costs. First, Mr. Doerk testified that the Utilities do not always immediately construct new facilities to meet increased customer demand that exceeds existing capacity. Tr. at 210-11. For example, Mr. Doerk described how increased demand from customers served through medium- or high-pressure portions of the Utilities' systems can be met by installing equipment on the customer's premises to permit service (increased throughput) at a higher pressure. Id. at 213-14. The Utilities' ability to increase capacity through system reconfigurations that allow greater throughput without constructing additional peak capacity is nowhere addressed in the Utilities' unqualified testimony or in the ECOSS submitted by Mr. Amen.

More important, City-CUB argue, is that Mr. Doerk confirmed that the Utilities' system capacity design decisions are based on *both* the demands of customers at the system peak and the load supplied to customers over periods far more inclusive than the moment of system peak. This testimony contradicts the Utilities' prepared testimony, including that of Mr. Amen, asserting categorically that the only consequential system design cost factor is peak demand. Indeed, Mr. Doerk himself stated in Direct Testimony that "Peoples Gas' system is designed . . . to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day." PGL Ex. ED 1.0 at 4. And, Mr. Amen asserted that,

> [t]he concept of Peak Demand Allocation is premised on the notion that investment in capacity is determined by the peak load(s) of the utility. Under this methodology, demand related costs are allocated to each customer class in proportion to the demand coincident with the system peak of that customer class.

PGL Ex. RJA 1.0 at 14.

According to City-CUB, Mr. Doerk's testimony reveals that the Utilities' process for deciding whether to invest in new capacity or rely on existing capacity to meet rising demand is driven by the need to meet loads throughout the year, and not just on the design day. Thus, they assert, the Utilities' proposal to allocate distribution costs based solely on peak demand does not reflect the realities of the Utilities' operations.

Moreover, City-CUB observe, Mr. Amen agreed that the extent to which new investment, extension or installation of mains, is required to serve new customers depends on whether the utility's service territory is urban or rural. Id. at 331. It is not clear whether in the context of this case, "for every situation" where a Peoples Gas customer can be added without installing additional footage of mains, there are "contrasting situations" where extension of mains is required, as Mr. Amen claimed. PGL Ex. RJA-1.0. This is a particularly relevant consideration for Peoples Gas because its service territory is predominantly urban. *See* PGL Ex. ED-1.0 at 3. Nor does Mr. Amen explain why, in cases where the utilities investment in mains is driven by the need to replace aging or deteriorating pipelines – a situation that Mr. Amen relegates to brief mention in his Direct Testimony, *see* PGL Ex. RJA-1.0 at 19 – what drives the level of investment is the peak load served by the main, rather than annual consumption or some other factor. These unresolved issues underscore that the Utilities have not established that the CP allocation methodology best reflects the cost causation drivers for their systems.

In addition, the Utilities have not shown that the CP allocation method reflects actual cost causation on their system. *See* City-CUB Init. Br. at 94-97. Although the Utilities continue to insist that demand-related costs are incurred entirely to meet peak demands, *see, e.g.*, NS-PGL Init. Br. at 143-44, their assertion was contradicted at the evidentiary hearing. Specifically, the Utilities' Vice-President for Gas Operations, Edward Doerk, candidly acknowledged under cross-examination that (1) the Utilities do not always immediately construct new facilities to meet increased customer demand that exceeds existing capacity, and (2) the Utilities' system capacity design decisions are based on both the demands of customers at the system peak and the load supplied to customers over periods more inclusive than just the system peak. *See* Tr. at 210-14 (Doerk); *see also* City-CUB Init. Br. at 94-97. Thus, the Utilities' proposal to allocate distribution costs based solely on peak demand does not reflect the realities of the Utilities' distribution operations.

According to City-CUB, no weight should be given to the Utilities' misleading suggestion that the A&P method assumes that the Utilities' distribution system was built entirely to meet average demand. No party disputes that the system must be able to meet peak demand. But that principle does not affect the propriety of using the A&P methodology to allocate demand-related costs. As the Utilities well know, the A&P method takes into account both average *and* peak demand in allocating distribution-related costs. *See, e.g.*, PGL Ex. RJA-1.0 at 15 (noting that the A&P methodology "often gives equivalent weight to peak demands and average demands"). In fact, Mr. Luth maintained that the "most significant factor in A&P is . . . peak demand because it represents approximately 3/4 of the allocation." Staff Ex. 19.0 at 6. Unlike the CP methodology, the A&P methodology, therefore, takes into account the relationship between investment in the distribution system and both kinds of demand that the Utilities are obliged to meet.

(4) AG

The AG explains that the ECOSS methodology proposed by Utilities' witness Amen allocates customer demand related costs based on coincident peak ("CP") demands. He testified that the CP demand estimates are based upon the engineering design-day demands that the Utilities use for planning purposes. PGL-NS Ex. RJA-1.0 at 19-21. According to City-Cub witness Thomas, this methodology results in an over-allocation of costs to residential heating customers and should be rejected by the Commission. CUB-City Ex. 1.0 at 72.

As explained by Mr. Thomas, allocating demand costs based solely on CP demand ignores the impact that average demand has on the system. Id. Because residential customers tend to use considerably more natural gas on peak days than on average days, their share of total system demand is considerably greater during peak times than it is on average. Id. Mr. Thomas noted, however, that peak usage occurs only one day out of the year, while customers actually use and benefit from the system every day of the year. Id. at 72, 73. Accordingly, "by allocating solely on the basis of peak demand, the Utilities attribute more costs to residential space-heating customers, and fewer costs to large volume customers than those customers actually cause." Id. at 73.

While there is a relationship between CP demand on the system and the cost of service, Mr. Thomas stated that there is an equally important relationship between average demand and the cost of the system:

> Allocating costs based on CP demand assumes that Peoples and North Shore's distribution systems were designed only to meet CP demands. This methodology further assumes that each customer class would only use the system during a single day of the entire year – the day that demand is the highest. This is clearly not how customers use the distribution system. Customers depend on the distribution system to meet their demands every day, not just when they are using the most natural gas. Id.

This Commission has previously endorsed this viewpoint in several dockets, including Docket Nos. 04-0779, 04-0476, 03-0008, 03-0009, 95-0219 and 94-0040.

Moreover, the Commission has consistently adopted an average and peak ("A&P") methodology for allocating distribution costs. Id. at 74. This methodology recognizes that while the system is sized primarily to address peak demands, customers use the system throughout the entire year. Id. Mr. Thomas noted that, from a cost-causation perspective, it is appropriate to recognize that cost is driven by demand and that peak demand is very different from average demand. Id.

The AG points out that Table 7 in Mr. Thomas' Direct testimony details the level of over-allocation to residential customers and under-allocation to large volume customers that occurs under the CP methodology. CUB-City Ex. 1.0 at 75. Demand-related costs should be allocated based upon an allocation factor that weights average demands at the system load factor, with peak demands weighted at 1 – system load factor). Id. at 74, 75. This methodology is reflected in Mr. Amen's alternative schedules PGL Ex. RJA 1.8 and NS Ex. RJA-1.8.

While Mr. Amen declared in his Rebuttal testimony that the Utilities' view that demand-related costs are incurred entirely to meet peak demands is "a necessary assumption that is grounded in the underlying engineering and cost characteristics of the distribution system," PGL-NS Ex. RJA-2.0 at 7, Mr. Thomas countered that this view is belied by the fact that the cost of distribution facilities are also a function of usage. CUB-City Ex. 2.0 at 28. Because customers rely on the distribution system to be available every time they desire gas (not just at peak demand), this requirement also drives costs. Mr. Thomas explained that "it is much more accurate to say that the system is designed and installed to meet year-round demand, but should be sized to meet peak demand." Id.

(5) Commission Analysis and Conclusion

The issue is whether common system distribution costs should be allocated on the basis of the CP method or the A&P methodology.

The Utilities preferred methodology is CP because, in their view, it most appropriately takes account of the specific systems that are sized to meet peak demands and, in doing so, adheres to the principle of allocating costs on a causal basis. Staff, the AG, and City-CUB, all maintain that an A&P method is more balanced because it weights 75% according to coincident peak and 25% according to average deliveries.

In every situation where it is reasonable to do so, the Commission will consider its own past practice in resolving an issue. Staff stipulates that over the past decade, the Commission has consistently found the A&P allocation of distribution system costs to be preferable to a CP allocation. There is nothing to persuade us differently in this Instance. In other words, the Utilities have not overcome the Commission-established and long-standing tradition of A&P methodology for allocating distribution costs.

b) Classification of Uncollectible Account Expenses Account No. 904

(1) The Utilities

In the ECOSS, the Utilities classified Account No. 904 costs, Uncollectible Account Expenses, as customer costs. They note, however, that Staff witness Luth would have Account No. 904 expenses be classified as a combination of customer costs, demand costs, and commodity costs, including gas costs. Staff Ex. 7.0. Mr. Luth would also apportion the uncollectible expense in each customer class to the respective demand, customer and commodity classifications by the relative weight or percentage of revenue requirement from each customer class resulting from demand costs, commodity costs, customer costs and gas costs.

The Utilities contend that their proposal is more appropriate because Account No. 904 costs are a function of customers' unpaid bills and not the underlying components of those bills. As such, they assert, the uncollectible expenses have no bearing on whether the expenses are fixed or variable charges or the specific costs which may be covered by those bills. Residential customers do not even receive fully allocated costs. NS-PGL Ex. RJA-2.0 at 13. Hence, any attempt to match the recovery of uncollectible expenses to specific charges is misplaced because the amount of uncollectible expense (or any other expense) that is recovered by the customer demand and distribution charges of a particular service schedule is uncertain because the revenues produced by any customer class are not necessarily equal to their fully allocated costs. Furthermore, the Utilities argue, the customer, demand and commodity related costs for a particular customer class are not translated directly into similar rate components in the Utilities' rate schedules. NS-PGL Ex. RJA-3.0 at 6. Mr. Luth's proposal regarding Account No. 904 should be rejected because he seeks to inappropriately use rate design as justification for cost classification and allocation in an ECOSS. This is polar opposite to what is conventionally sought to be achieved by an ECOSS. An ECOSS drives rate design and rate design should never drive the cost of service.

(2) Staff

Staff notes that the Utilities' cost of service study witness has recognized that costs, not recovered from uncollectible accounts, are a blend of customer costs billed through the customer charge, and unrecovered demand and distribution costs billed through variable usage and demand charges. Tr. at 343, 346-47 (Amen).

Staff illustrates that if a customer with a customer charge of $19.00 and usage charges of $15.00 does not pay his bill, an amount totaling $34.00 becomes uncollectible. And, if another customer with the same $19.00 customer charge but $400.00 in usage charges does not pay her bill, $419.00 becomes uncollectible. Tr. at 346-47. According to Staff, the customer who does not pay her $419.00 bill adds a far greater amount to uncollectible expense (because her bill included $400.00 in usage charges compared to the $34.00 uncollectible account that had only $15.00 in usage charges).

From this, Staff derives that uncollectible accounts expense are affected by the charges on a customer's bill that become uncollectible. In Staff's view, since a portion of a customer's account that becomes uncollectible is comprised of a fixed customer charge, it is reasonable to recover a portion of uncollectible accounts expense through the customer charge. And, since another portion of a customer's account that becomes uncollectible is comprised of variable usage and possibly demand charges, it is similarly reasonable and appropriate, to recover a portion of uncollectible accounts expense through variable usage and demand charges. Nonetheless, and for reasons that do not make sense to Staff, the Utilities claim that uncollectible expenses have no bearing on whether the expenses are fixed or variable charges or the specific costs which may be covered by those bills. NS-PGL Init. Br. at 145.

According to Staff, the Utilities are wrong in claiming that Mr. Luth seeks to use rate design as justification for cost classification and allocation in an ECOSS, because he is not seeking to change the results of the ECOSS to change how rates are designed. Staff explains that the expense of uncollectible accounts is a function of, and affected by, the underlying charges on a customer's bill that is unpaid. As such, Staff asserts, uncollectible accounts should not be considered solely on customer cost because these are not the only costs that are not paid on an uncollectible account. Therefore, uncollectible accounts expense should be allocated according to the origin of the charges because the costs included in all charges on an uncollectible account are not recovered as a result of bills that are not paid. Staff asks the Commission to conclude that the amount of uncollectible accounts expense is caused by the charges that appear on the bills that become unpaid and uncollectible, making it appropriate to allocate uncollectible accounts expense according to the blend of costs that result in the charges on bills of uncollectible customer accounts.

(3) Commission Analysis and Conclusion

The issue here is whether Account No. 904 should be classified as customer costs as the Utilities have proposed.

Having studied the positions at hand, the Commission accepts Staff witness Luth's proposal that Account No. 904 expenses should be classified as a combination of customer costs, demand costs, and commodity costs including gas costs. The Commission further accepts Mr. Luth's proposal to apportion the uncollectible expense in each customer class to the respective demand, customer and commodity classifications by the relative weight or percentage of revenue requirement from each customer class resulting from various categories of costs. The analysis provided by Staff in this instance is clear, thorough and highly persuasive.

Therefore, the Commission approves, as reasonable and appropriate, Staff's classification of expenses recorded in Account No. 904, Uncollectible Account Expenses.

c) Allocation of Costs to S.C. No. 1H and S.C. No. 1N

(1) North Shore / Peoples Gas

The Utilities' propose to bifurcate S.C. No. 1 into heating (S.C. No. 1H) and non-heating (S.C. No. 1N) categories. According to the Utilities, doing so will allow for better alignment of costs and revenue recovery, and also provide more equity between and within rate classes, by setting rates closer to the costs of service. PGL Ex. VG-1.0 REV at 11, NS Ex. VG-1.0 3REV at 9. The Utilities' ECOSS shows a significant difference in fixed costs for heating and non-heating customers. They contend that fixed costs for heating customers are twice as high as those of non-heating customers. A single service classification for heating and non-heating customers, the Utilities argue, would slow the movement of non-heating customers toward cost-based service rates. PGL Ex. VG-1.0 REV at 1; NS Ex. VG-1.0 2Rev. at 9.

The Utilities contend that they have properly classified customers into heating and non-heating designation. The Utilities further explain that they have attached such designations to their small residential accounts for at least twenty years. These designations, they note, were made on the basis of information provided by the customers at the time service commenced or in follow-up calls from the Utilities, through service inspections, and further through billing department analyses of customer account usage.

The Utilities maintain that they have provided evidence showing that 97% of Peoples Gas' and 91% of North Shore's S.C. 1N monthly bills are for 50 therms or less, which supports the assumption that S.C. 1N customers generally use less than 500 annual therms, while heating customers would be expected to use more than 500 therms a year. Furthermore, the Utilities maintain that they have demonstrated that usage is one of a few important factors that would be considered to ensure that customers are properly classified. NS-PGL Ex. VG-2.0 at 32.

(2) Staff

Staff witness Luth recommended that North Shore and Peoples Gas SC 1N and SC 1H customers have the opportunity to be billed for a minimum of 12 months under SC 1N and SC 1H, depending upon how the customer believes that gas service will be used over the next heating season. NS-PGL Init. Br. at 149 and Staff Ex. 19.0 at 9-11. If the Utilities cannot administer and advise SC 1N and SC 1H customers of a potential choice between billing under either SC 1N or SC 1H, Staff would have the Utilities abandon their proposal. Staff Ex. 19.0 at 11. Cost of service for SC 1N and SC 1H should be combined, with rates based upon the combined cost of service with the lower customer charge with Rider UBA that is between the proposed SC 1N and SC 1H customer charges, as shown in the surrebuttal testimony of North Shore and Peoples Gas witness Grace. Staff Init. Br. at 236 (*referencing* Customer Charge with Rider UBA in Exhibit VG 3.1, columns [B] and [D], line 9). Staff does not recommend that the Commission authorize Rider UBA, but it does not make sense that a customer charge is lower with Rider UBA because the proposed Rider UBA would be a variable charge based upon therms delivered. Staff Init. Br. at 236.

Staff explains that its recommendations attempt to address significant bill impacts on what probably would be a small number of SC 1N customers. Nonetheless, Staff maintains, relatively high-use SC 1N customers should not pay more for the same therms as a SC 1H customer simply because the SC 1N customer does not use natural gas for space heat. Even if 97 percent of potential Peoples Gas SC 1N bills and 91 percent of potential North Shore SC 1N bills would be for 50 therms or less, 3 percent and 9 percent of those respective Peoples Gas and North Shore SC 1N bills would be for more than 50 therms. With rate differentials on deliveries over 50 therms of 38.679¢ per therm at Peoples Gas and 27.406¢ per therm at North Shore under SC 1N and SC 1H rates proposed by the Utilities (rate tables in Staff IB at 237-239), therms delivered under SC 1N become far more expensive than therms delivered under SC 1H in short order. For 3 percent of potential Peoples Gas SC 1N customers and 9 percent of potential North Shore SC 1N customers, Staff believes that the billing consequences could be significant. Staff's recommendation is that the basis for differentiating SC 1N and SC 1H customers should be usage, with choice available to customers, so as to prevent unfair bill impacts.

Since the Company apparently cannot administer providing notice of choice, and guidance for that choice, to SC 1N and SC 1H customers, Staff believes that SC 1N and SC 1H cost of service should be combined. Rates for a single SC 1 residential customer class should be based upon a $15.79 customer charge at Peoples Gas and $14.69 customer charge at North Shore, with usage charges recovering the balance of the combined SC 1 costs from customers at each respective company at the percentage of revenues and cost of service recommended by Staff.

(3) City-CUB

City-CUB question the need for the Utilities' bifurcation proposal. They note GCI witness Glahn explained that, according to the Utilities' own work papers, the per-unit cost of regulators for non-heating customers is less than a third of the cost for heating customers, and that the per-unit cost of services for non-heating customers is approximately one-third the cost for heating customers. GCI Ex. 3.0 REV., at 16-17. And, Mr. Glahn added that this alleged difference seems implausible, because the cost of installing services presumably would depend largely on labor and construction costs that "should vary little by the size of the pipe, at the sizes typically used for residential customers." Id. at 17.

City-CUB observe Mr. Glahn to have questioned whether the utility would dig up an old service and replace it with a larger one every time a non-heating customer decides to install a gas furnace and become a heating customer, or instead simply install from the beginning services that would accommodate a range of end uses. Id. at 7-11; *see also* Tr. at 210-11 (where Mr. Doerk states that: "[o]n a case-by-case basis . . . it is possible" that a residential customer could double consumption without requiring a larger service pipe). In City-CUB's view, the Utilities have not satisfactorily explained why there is ostensibly such a large disparity in the cost of services for heating and non-heating customers in S.C. 1.

City-CUB note Mr. Amen stated that the magnitude of the asserted cost difference is attributable to the "occurrence of multiple S.C. No. 1 non-heating customers served by shared gas lines" and the fact that nearly half of Peoples Gas's residential heating customers are served by a separate service line. PGL-NS Ex. RJA-2.0 at 15; PGL-NS Init. Br. at 147. Yet, in her testimony, Ms. Grace stated that S.C. No. 1 includes only dwellings with two or fewer units. Tr. at 959. If this is the case, City-CUB considers Mr. Amen's explanation for the cost of service differential between S.C. 1 heating and non-heating customers to be implausible. It seems highly unlikely, they argue, that service costs vary significantly, i.e., by a 3-to-1 ratio, as calculated by Mr. Glahn, according to whether the service is used by one customer or is shared by two customers.

City-CUB witness Mr. Amen testified that, a "relatively prevalent practice" in the gas distribution industry is to have two single-family dwellings share a single service. In such cases, he added, "the service line has enough capacity, generally speaking, that it doesn't require a larger service than it otherwise would to service a single customer," depending on the pressure system to which the service is connected. Tr. at 321. Further, City-CUB observe Ms. Grace's account that, "[c]ertain non-heating customers may consume larger quantities [of gas] than heating customers in a given month due to personal preferences such as cooking, water heating or clothes drying as well as the efficiency of appliances used for such activities." NS-PGL Ex. VG-3.0REV. at 8. The ECOSS results notwithstanding, City-CUB observe that the Utilities have never asserted that larger services must be installed to serve such non-heating customers even though their loads may exceed those of heating customers. Nor is it clear to City-CUB, whether the Utilities' claim that "[a]s a group, heating customers place a significantly higher peak load on the system than do non-heating customers" refers to all heating and non-heating customers or just heating and non-heating customers in S.C. 1. PGL-NS Init. Br. at 148.

According to City-CUB, the Utilities can not expect the Commission to approve the bifurcation of S.C. 1 into heating and non-heating sub-classes based on a questionable cost of service differential that may or may not apply to heating and non-heating customers *in S.C. 1*. They assert that the Utilities have failed to demonstrate that the ostensibly significant difference in the cost to serve S.C. 1 customers is due to a heating/non-heating distinction rather than to the single/multiple family factor that Mr. Glahn identified.

As to the Utilities' contention that S.C. 1H customers would pay lower rates under bifurcation than under Mr. Glahn's recommended rates (PGL-NS Init. Br. at 148), City-CUB believe that this claim fails to consider the potentially significant impact on such customers' usage of energy efficiency programs, particularly those targeted at low-income customers. *See* GCI Ex. 6.0 REV. at 13.

Further, City-CUB argue, the Utilities have not demonstrated that bifurcation would mitigate any subsidy running between heating customers and non-heating customers. They point out that the Utilities appear to agree that, to the extent there currently is an intra-class subsidy within S.C. 1, it is from heating to non-heating customers. PGL-NS Init. Br. at 148-49; GCI Ex. 3.0 REV. at 22-23. This conclusion is based on Peoples Gas's class revenue/embedded cost comparison, PGL Ex. VG-1.3 at 2, which shows that at current rates, non-heating customers pay 62.55 percent of their proposed cost of service, while heating customers pay 70.93 percent of their proposed cost of service – a gap of 8.38 percent. GCI Ex. 3.0 REV. at 22-23. Although the Utilities' proposed rate increase allocation would move both groups closer to their respective costs of service, City-CUB contend that this allocation would narrow the gap in the percentages of cost of service paid by S.C. 1N and 1H customers by a negligible amount – from 8.38 percent to 8.3 percent. Thus, to the extent heating customers are subsidizing non-heating customers under current rates (when compared with each sub-class's proposed cost of service), City-CUB argue that bifurcation would not eliminate or meaningfully reduce that subsidy – one of the Utilities' stated goals in proposing bifurcation. *See* PGL Ex. VG-1.0, 2 REV. at 11; NS Ex. VG-1.0, 3 REV. at 9.

Further, City-CUB argue, the Utilities' claim that bifurcation "does not result in higher rate increases for heating customers," is irrelevant to the merits of bifurcation. PGL-NS Init. Br. at 149.

According to City-CUB, the Utilities have failed to show that bifurcation of S.C. 1 is warranted. The evidence of record, they contend, establishes neither that the alleged disparity in the cost of serving S.C. 1 heating and non-heating customers is significant, nor that bifurcation would mitigate any intra-class subsidy within S.C. 1. Accordingly, they argue, the Utilities' bifurcation proposal should be rejected.

(4) AG

The AG notes that the Utilities proposed the bifurcation because it would allow each company to meet its first two objectives, which are to (1) better align costs and revenue recovery and (2) provide more equity between and within rate classes. PGL Ex. VG-1.0 at 11; NS Ex. VG-1.0 at 9. But, the AG argues, Mr. Glahn testified that the proposed bifurcation results in significantly higher rate increases for heating customers. GCI Ex. 3.0 at 17. The AG explains this to mean that the larger increase is imposed on customers with less flexibility in peak winter consumption and, because their usage is not limited to cooking appliances, less ability to substitute energy sources. And, the AG maintains, the proposed bifurcation also shifts the cost allocation subsidy, so that under the Utilities' proposal, heating customers will be subsidizing non-heating customers. Id. at 22. Before application of the proposed rate increase, the AG points out, non-heating customers pay 62.55 percent of the cost of service for this group, and heating customers pay 70.93 percent of their costs. Id. Because the AG believes that the Utilities' proposed rate changes would only narrow the gap in terms of cost allocation by less than a percentage point, "the only thing accomplished by the proposed bifurcation is to saddle heating customers with a much larger increase in customer charges." Id. at 23.

According to the AG, Staff witness Michael Luth likewise expressed concern regarding the proposed residential class bifurcation. In rebuttal testimony, he proposed that residential non-heating customers be permitted to choose either S.C.1N or S.C.1H during the next 12 months on their bills due during the non-heating months of June 15th through October 15th, out of concern that non-heating customer bills could at some point exceed heating customer bills. Staff Ex. 19.0 at 9-10.

In rebuttal testimony, Utilities' witness Amen opined that Mr. Glahn "failed to account for the occurrence of multiple S.C. No. 1 non-heating customers served by shared gas service lines." PGL-NS Ex. RJA-2.0 at 15. He stated that 97 percent of Peoples Gas non-heating residential customers share a gas service line while almost half (47%) of the residential heating customers are served by a separate, dedicated line. Id. Thus, the principal driver for the bifurcation is not heating vs. non-heating, but rather multi-family vs. single family or single meter vs. separately metered. GCI Ex. 6.0 at 4.

In rebuttal testimony, the AG observes Mr. Glahn to have acknowledged this new distinction, observing that it "goes a long way to explain the cost differential between the two groups." Id. He observed, however, that the cost-causation information in this observation regarding multiple units is largely lost in the Utilities' artificial distinction between "heating" and "non-heating". Id. Thus, he concluded, and the AG agrees, that the heating/non-heating bifurcation should still be rejected in this case, and after the Utilities "have properly accounted for the multi-family phenomenon that actually drives the cost of service differences of S.C.1 subgroups", the Utilities should propose a new cost of service study in a future rate case that supports a more appropriate bifurcation. Id.

The AG maintains that the Utilities' proposed bifurcation of the residential class should be rejected.

(5) North Shore / Peoples Gas Response

The Utilities contend that dividing S.C. No. 1 customers into multi-family and single family classes, as proposed by GCI witness Glahn, would do nothing to help recognition of the fact that heating customers place a significantly higher peak load on the system than do non-heating customers. NS-PGL Ex. RJA-3.0 at 8.

It is also undisputed, the Utilities observe, that under the current rate structures, an intra-class subsidy from the Utilities' heating customers to non-heating customers exists, and that the single rate for heating and non-heating customers slows the movement of non-heating customers' rates toward cost. PGL Ex. VG-1.0 REV at 11, NS Ex. VG-1.0 2REV. at 9. According to the Utilities, they have also demonstrated that fixed costs for heating customers are twice as high as those for non-heating customers, and that such a significant difference would result in the recovery of fixed costs through fixed charges under a single rate which could overburden small non-heating customers. PGL Ex. VG-1.0 REV at 11; NS Ex. VG-1.0 3REV at 9.

Even Mr. Glahn, the Utilities observe, admits to only having problems with the implementation of the bifurcation, and he further admits that the Utilities' proposed heating and non-heating distinction is "common in the industry". GCI Ex. 3.0 REV., at 16. The Utilities understand Mr. Glahn's perceived implementation problems to be that: (1) the proportion of costs assigned to heating customers appears "implausibly" high; (2) rates disproportionately impact low and fixed income customers; (3) there will be little shift in the subsidy of non-heating customers by heating customers under the Utilities' proposal. Id. at 16. Each of these issues, they assert, is without support in the record.

First, Utilities note, Mr. Glahn's assertion that the cost differentials between S.C. No. 1 and S.C. No. 1N are "implausibly high" is irrelevant and, in any event, is based upon flawed analysis. His "average per customer" calculations for service plant, the Utilities point out, ignore that multiple residential heating customers are served by shared gas service lines - a predominant circumstance on the Peoples Gas system. NS-PGL Ex. RJA-2.0 at 15. Peoples Gas' ECOSS properly accounts for the sharing of service lines by multiple customers. Id. at 16. According to the Utilities, Mr. Glahn also inaccurately, and without support, generalizes that multi-family units spread fixed costs over a larger customer base driving down costs per customer. GCI Ex. 6.0 REV at 4. For their part, the Utilities assert, the bifurcation into heating and non-heating classes appropriately recognizes customers' respective load characteristics by reflecting the single largest component of distribution plant which drives cost responsibility, *i.e.*, the cost of mains. The capacity cost of mains is driven by peak load and, as a group, heating customers place a significantly higher peak load on the system than do non-heating customers. Dividing S.C. No. 1 customers into multi-family and single family classes would not assist in the recognition of this important cost causation factor. NS-PGL Ex. RJA-3.0 at 8.

Second, the Utilities consider Mr. Glahn's criticism, that the 1N/1H bifurcation disproportionately impacts low income customers (GCI Ex. 3.0 REV, 17-18) to be unavailing. It was established by Ms. Grace, the Utilities point out, that the rates under the Utilities' bifurcation proposal would be lower than those proposed by Mr. Glahn, and particularly during the winter. NS-PGL Ex. VG-2.0 at 33.

Finally, Utilities contend, the assertion that bifurcation is not needed because there is no shift in the subsidy of non-heating customers by heating customers also lacks merit. A primary purpose of bifurcation, Utilities assert, is to better align costs and revenue recovery. PGL Ex. VG-1.0 REV at 11; NS Ex. VG-1.0 3REV at 9. Because the fixed costs for S.C. No. 1H are twice as high as the fixed costs for S.C. No. 1N, the current single service rate structure does not appropriate align costs with their causal factors and thus smaller use, non-heating customers are overburdened. Id.; Id. at 9-10. The Utilities observe Mr. Glahn to support his assertion by comparing the difference between the cost recovery percentages of S.C. No. 1 and S.C. No. 1N before and after the proposed rate increase (8.38% and 8.3%, respectively), and then, on this basis, concluding that since the differences between the percentages remain basically the same before and after the proposed rate increase, bifurcation of S.C. No. 1 is unwarranted. GCI Ex. 3.0 REV at 23. The Utilities' view this simplistic comparison to prove nothing with respect to the appropriateness of bifurcation, nor does it serve to address or refute Ms. Grace's testimony establishing that the proposed bifurcation does not by itself result in higher rate increases for heating customers, contrary to Mr. Glahn's assertion. NS-PGL Ex. VG-2.0 at 33-34.

While Staff witness Luth did not oppose the bifurcations, the Utilities recognize that he did set out a proposal to determine customers' eligibility for S.C. Nos. 1N and 1H. His initial proposal was problematic, they claim. Id. at 26-31. And, a substitute proposal did not eliminate the problems and only introduce new problems. NS-PGL Ex. VG-3.0 at 7-9. According to the Utilities, Mr. Luth has not demonstrated that his proposals are warranted, practical or workable.

(6) Commission Analysis and Conclusion

The issue at hand is whether S.C. No. 1 should be bifurcated into heating and non-heating customers. While the Utilities urge bifurcation, the GCI parties oppose it, and Staff appears to have an implementation issue. This situation requires the Commission to apply its best and considered judgment on the evidence and arguments presented.

The Commission is not persuaded by the opposition or the recommendations of GCI witness Glahn. Notably, he acknowledges that the heating and non-heating distinction is "common in the industry." Yet, he would dismiss the bifurcation proposal here on little more than his belief that the cost differentials between S.C. No. 1H and S.C. No. 1N are too high. We consider the Utilities to have effectively challenged Mr. Glahn's analysis and shown to the Commission that it has no bearing on whether the Utilities proposed bifurcation is appropriate, and further that his suggestion of a multi-family and single family bifurcation is unsupported. We further note that Mr. Glahn's average per customer calculations for service plant ignore the occurrence of multiple S.C. No. 1N customers served by shared gas service lines, while the Utilities' ECOSS properly account for the sharing of service lines by multiple customers.

In our view, the Utilities' bifurcation of S.C. No. 1 into heating and non-heating classes appropriately recognizes those customers' respective load characteristics by reflecting the single largest component of distribution plant which drives cost responsibility, i.e., the cost of mains. The Commission is unconvinced that dividing S.C. No. 1 customers into multi-family versus single family classes, as proposed by Mr. Glahn, would help to recognize cost causation as well as does the Utilities' heating and non-heating classification proposal.

Mr. Glahn's criticism that the 1N/1H bifurcation disproportionately impacts low income customers is unconvincing. We see evidence from the Utilities to show that their bifurcation proposal will actually result in lower rates, especially in the winter. This we cannot disregard. Finally, we observe that both the Utilities and Mr. Glahn agree that a subsidy from heating to non-heating exists. While Mr. Glahn appears to complain that there is lack of significant change in nominal percentages before and after the proposed bifurcation, we are not convinced that that this ground is sufficient enough to reject the Utilities' S.C. No. 1 bifurcation proposal given all of the other justifications for the proposal on record.

While the Commission is not persuaded that bifurcation is inappropriate simply because of the implementation issues raised, we are concerned about the possible rate impacts identified by the Staff. In particular, we observe that there could be a small number of non-heating customers who have relatively high usage in some months, and thus, would pay more than a heating customer with the same usage. The Commission, finding such an account on the record, is concerned about that result. Accordingly, and on the entirety of the evidence and the arguments presented, the Commission rejects the Utilities' proposed bifurcation in these premises.

d) Allocation of Distribution Plant Account No. 385

(1) Peoples Gas

Peoples Gas allocated the majority of Account No. 385 costs, which represent industrial measuring and regulating station equipment expense, to S.C. No. 2.

(2) CUB-CITY

With respect to the costs recorded in FERC Account No. 385 – Industrial Metering and Regulating Station Equipment, City-CUB observe that the Utilities have directly assigned the costs to S.C. 2 and 4. Because such costs can be attributed to individual customers, they assert that, as a matter of fairness, this should be done..

City-CUB note Mr. Amen to have agreed that direct assignment of costs to the individual cost causers is preferable to allocation based on secondary factors. Tr. at 324. And, they observe, it is undisputed that: (a) the Utilities can track FERC Account No. 385 costs to individual customers; (b) customers that cause the Utilities to incur costs recorded in Account No. 385 may migrate from one rate classification to another; and (c) the number of such customers is small. NS-PGL Ex. RJA-2.0 at 17-18.; *see also* Tr. at 324-25 (Amen).

Based on these considerations, City-CUB point out, GCI witness Glahn recommended that the Utilities impose a special "facilities charge" or "metering surcharge" on the individual customers causing the costs in Account No. 385, regardless of the rate classifications to which the customers belong. GCI Ex. 6.0 REV. at 5. Direct assignment to individual customers, City-CUB argue, would ensure that the Utilities recover Account No. 385 costs entirely from the actual cost causers – not the cost causers as well as other non-cost causers who happen to be in the same customer class as the cost causers. Although Mr. Amen claimed at the evidentiary hearing that Account No. 385 costs were directly assigned, City-CUB observe that he really meant they were assigned to entire customer classes (S.C. 2 and 4, *see* PGL Ex. RJA-1.0 at 29) and not to the individual cost causers within those classes. Tr. at 324.

City-CUB note Mr. Glahn to have discussed a particularly blatant example of the unfairness of assigning Account No. 385 costs to entire customer classes rather than individual customers. This, they explain, arose out of the rebuttal testimony of Mr. Amen wherein he identified a situation where:

> [A] current S.C. No. 2 customer, an electric power plant with test year consumption in excess of 500,000 therms, which had previously taken service under S.C. No. 7 (Contract Service). This customer alone represents $136,000 (over one-third) of the $373,000 recorded in Account No. 385. Thus, large industrial customers can and do receive service under S.C. No. 2, which may require significant investment in metering and regulator facilities. PGL Ex. RJA-2.0 at 17-18.

As Mr. Glahn observed, general service customers such as those in S.C. 2 also "typically include small businesses, such as dry cleaners, fast food franchises, small offices and the like," GCI Ex. 3.0 REV. at 25. Under the Utilities' proposed assignment of Account No. 385 plant investments, customers in S.C. 2 – including small businesses – would pay for special industrial equipment needed to serve an electric power plant or similarly large customers, not because they required such equipment, but because they are served under the same rate classification as the customers that do. It is patently unfair, the City-CUB argue, to charge Account 385 costs to any customers other than the large customer needing the special equipment associated with Account 385 costs.

Nothing in Mr. Amen's testimony, City-CUB assert, serves to undermine Mr. Glahn's recommendation. In their view, Mr. Amen's opinion, *see* NS-PGL Ex. RJA-3.0 at 10-11, that direct assignment of Account No. 385 investments raises the question of whether other customer-specific costs should be directly assigned to individual customers – a result that Mr. Amen characterizes as impractical – does not defeat the reasons that Account No. 385 can and should be assigned to the customers causing such costs. Such other customer-specific costs are not at issue here, City-CUB argue. And, even if Mr. Amen is correct that removing gross facilities costs in Account 385 would have a "negligible impact" on S.C. 2 customer charges, *id.* at 11, City-CUB maintain that the cost impact of following sound cost allocation principles is not a basis for ignoring them. Here, they contend, the applicable principle is that costs that can be directly assigned to particular customers should be so assigned – an approach that, according to Mr. Amen, cost analysts seek to maximize. PGL Ex. RJA-1.0 at 12. That doing so with respect to Account No. 385 investments incurred to serve one particular customer ostensibly would have little impact on customer charges for S.C. 2 does not excuse the Utilities' failure in this instance to follow the overriding preference for direct assignment of costs.

City-CUB would not have the Commission be misled by Mr. Amen's suggestion at the evidentiary hearing that charging Account No. 385 costs to the cost causer(s) within, but not other members of, that customer's service would amount to "taking a single customer out of" the applicable service classification. Tr. at 326. According to the City-CUB, the Utilities do charge individual customers in various customer classes the customer-specific costs that other customers in those classes do not pay. For example, under the Utilities' Rider 4, Extension of Mains, when a customer requests that the utilities install a main in a different location than is required to provide service, the individual customer bears the incremental cost of meeting that customer's preferences. *See* PGL Ex. VG-1.0 3REV. at 36. And, as NS-PGL witness Valerie Grace agreed on cross-examination, recovering customer-specific costs from an individual cost causer – but not from other customers in the same customer class – does not affect the customer's membership in a service classification. *See* Tr. at 967-68.

According to City-CUB, the Utilities offer no sound reason for refusing, with respect to Account No. 385 plant, to implement its practice of directly assigning costs to the cost causers. Because Account No. 385 costs can be tracked to particular customers, they assert that such costs should be charged to these customers, and only to these customers.

(3) AG

The AG explains that the Utilities' Distribution Plant Account No. 385 is described by the Federal Energy Regulatory Commission ("FERC") as industrial measuring and regulating station equipment serving large industrial customers. GCI Ex. 3.0 at 24. The testimony of Mr. Amen, the AG observes, indicates that the Utilities can track these costs to individual customers, including an electric power plant that represents one-third of the cost amount recorded in Account No. 385. And, the small number of customers that trigger these costs may move from one rate classification to another. PGL-NS Ex. RJA 1.0 at 17. Despite these facts, the AG notes that the Utilities' ECOSS assigns Account No. 385 costs to all customers within S.C. 2 and 4. Id. at 28, 29.

On these facts, the AG notes, Mr. Glahn explained that "it only makes sense to charge a special 'facilities' charge or 'metering surcharge' to these individual customers. GCI Ex. 6.0 at 5. He further noted that: "It makes no sense for a dry cleaner, a small restaurant, or another small business in S.C. No. 2 to pay for the special, industrial-grade equipment needed for an electric power plant or a similar customer, just because that customer decided to switch from S.C. No. 7 to S.C. No. 2." As an example, Mr. Glahn noted if the electric power plant causing one-third of the account's costs moves back into S.C. No. 7, small business in S.C. No. 2 may be paying for these costs for years "even though the customer causing those costs is not even a member of the class and may be paying for the same costs again in its new rates." Id. at 6.

The AG notes Peoples Gas to argue that its methodology of assigning Account No. 385 costs results in *de minimis* price changes to S.C. No. 2 customers. PGL-NS Int. Br. at 150. This is not a persuasive argument, the AG contends, given the Utility's admission that: (1) the number of customers who trigger the cost is small; and, (2) the costs can be traced to individual customers. The AG urges that Mr. Glahn's common sense approach to assigning Account No. 385 costs be adopted by the Commission. Such a cost assignment, the AG asserts, would promote the goals of equity and fairness in the allocation of the Utilities' costs.

(4) Peoples Gas' Response

According to Peoples Gas, it is undisputed that: (1) the Utility can track FERC Account No. 385 costs to individual customers; (2) customers that cause Peoples Gas to incur costs recorded in Account No. 385 may migrate from one rate classification to another; and (3) the number of customers who cause Peoples Gas to incur such charges is small. NS-PGL Ex. RJA-2.0 at 17-18; *see also* Tr. at 324-25 (Amen). Nevertheless, Peoples Gas argues, these facts do not support Mr. Glahn's various proposals.

The AG similarly offers no authority for its position that there is an "overriding preference" for direct assignment of costs. Instead, the AG joins GCI in singling out particular costs and declaring that they should not be allocated to the class simply because they are identifiable to a specific customer. As Mr. Amen testified, there are many costs that could be so identified, and to begin with Account No. 385 costs could open the floodgates for broader direct assignment. PGL-NS Ex. RJA-3.0 at 10. This, Peoples Gas argues, can only lead to fractured and unnecessarily numerous rates and charges for the Utilities. Instead, the Utilities propose that a sound rate structure should include the practical attributes of simplicity, understandability, certainty and feasibility of application. Id. at 10-11.

(5) Commission Analysis and Conclusion.

The issue at hand is whether Account No. 385 costs should be directly assigned, to individual customers for the purpose of determining customer–specific charges, as proposed by GCI but as opposed by Peoples Gas.

We pay special attention here to the respective testimonies of the Utilities witness Amen and the GCI's witness Glahn. On the basis of our review, Mr. Glahn's account and his reasoning are far more persuasive than anything we hear on the Utility's side.

Account No. 385 represents industrial measuring and regulating station equipment expense. Mr. Glahn proposes that Account 385 costs should be directly charged as a facilities charge or metering surcharge to the individual customers generating those costs and for reasons that Peoples Gas can track the costs of Account No. 385 facilities to individual customers; the customers may move from one rate classification to another; and the small number of customers causing the cost justifies a direct charge.

The Commission is far less impressed with the Utility's claim that the overall impact of the issue Mr. Glahn raises is extremely small, i.e., Account No. 385 represents less than 0.04% of Peoples Gas' customer related distribution plant. In our view, there is much more to the situation. Mr. Glahn's proposal rests on questions of fairness and equity with respect to the treatment of customers whose costs can be specifically identified to them. Where, as here, the Commission sees that the Utilities have the capability to identify the specific plant costs of meters, regulators and services with individual customers in all of its service classes, we consider it appropriate to rely on those attributes. To the extent practicable, a sound rate structure should include the practical attributes of simplicity, understandability, certainty and feasibility of application. In the final analysis, the Commission finds GCI witness Glahn's proposal to be consistent with these objectives, fair in implementation, and it is approved.

e) Differentiated Class Rates of Return

(1) North Shore / Peoples Gas

The Utilities assert that they have satisfied the requisite statutory burden with respect to their proposed allocation of the revenue requirement. The Utilities calculated, at present rates, an average return in their respective ECOSS' of 4.88% for Peoples Gas and 7.12% for North Shore. PGL Ex. RJA-1.0, 33; NS Ex. RJA-1.0, 33. The Utilities' witness, Mr. Amen, testified that his ECOSS allocates revenue responsibility at an equalized class rate of return on investment of 8.25% for Peoples Gas, and 8.57% for North Shore, under proposed rates. PGL-NS Ex. RJA-1.0 at 2.

(2) CUB-CITY

City-CUB note that the ECOSS prepared by Utilities witness Amen allocates revenue responsibility at equal class rates of return. NS-PGL Ex. RJA-2.0 at 19. As such, they explain, the ECOSS is premised on the assumption that each customer class contributes the same level of risk to the Utilities' overall risk profile. City-CUB Ex. 2.0 (Public) at 29. According to City-CUB witness Thomas, however, this assumption is unsupported. And, as Mr. Thomas explained, there is ample reason to conclude that the relative risk of serving customers varies by customer class. In particular, he stated that:

> [c]ommercial and residential customers use gas very differently, and their usage is affected by different factors. For example, residential usage tends to vary with weather, while commercial and industrial usage tends to vary with general economic conditions. This means that there are very different risk factors related to the revenue the Utilities receive from each customer class.

City-CUB Ex. 1.0 at 77.

City-CUB maintain that Mr. Amen did not address these considerations, and only rejoined that no evidence has been presented suggesting that adopting risk-adjusted class rates of return is appropriate "for consideration in this instant case." NS-PGL Ex. RJA-2.0 at 19. According to the City-CUB, this assertion reverses the statutory allocation of the burden of proof. They assert that the utilities alone – not Staff or intervenors – bear the burden of proof to establish that their proposals are just and reasonable. 220 ILCS 5/9-201(c). To demonstrate that the Utilities have failed to meet their statutory burden with respect to their proposed allocation of the revenue requirement, City-CUB need not adduce evidence disproving the Utilities' *assumption* that the risk that the Utilities will not recover the costs of service does not vary by customer class. In the view of City-CUB, it is sufficient to point out, as Mr. Thomas did, that "there is "absolutely no evidence" supporting their assumption. City-CUB Ex. 2.0 (Public) at 29.

The City-CUB further claim that the Utilities' apparent reliance on speculation in allocating their revenue requirement makes plain that the Commission should avoid treating the ECOSS as a flawlessly objective basis for apportioning the revenue requirement among the customer classes. To be clear on this, City-CUB do not advocate that the Commission completely disregard the Utilities' ECOSS. Indeed, their witness Thomas explained that the ECOSS can be a useful starting point – albeit not the conclusive basis – for setting just and reasonable rates and charges. City-CUB Ex. 1.0 at 78. But to the extent the ECOSS is used for that purpose, City-CUB agree that the Commission should ensure that the study attributes costs to each customer class as accurately as possible. *See* Id.

(3) North Shore / Peoples Gas Response

The Utilities point out that City-CUB witness Thomas was the only witness to interpret their ECOSS methodology as assuming that each customer class contributes in precisely the same way to the Utilities' required rate of return. In addition, they note, Mr. Thomas to suggest that residential customers' gas usage is affected by the weather, while commercial customers' usage is affected by economic conditions, such that each customer class must provide a different level of risk to the overall cash flow risk of the Utilities and that each should pay rates which are established under separate rate of return assumptions. The Utilities note, however, that Mr. Thomas made no effort to support his observation with an analysis of these purported different risks. Indeed, he admitted that he was not even proposing any specific adjustments, but merely making an observation to cast doubt on Mr. Amen's ECOSS results. CUB-City Ex. 1.0 at 77.

City-CUB maintain that the Utilities failed to carry their burden of proof on this issue, but the Utilities assert that their burden centers around whether they have properly identified the cost responsibility of the customer classes on an equal footing at the system average or "equalized" rates of return, which provides the correct starting point for determining an appropriate level of class revenue responsibility. The Utilities submit that they have done just that.

(4) Commission Analysis and Conclusion

The Commission is unpersuaded with the analysis and arguments of City-CUB and Mr. Thomas. There is no support for the position and City-CUB misapprehend the burden of proof in this instance. The Commission finds that, absent some demonstrated causal link between a utility's customer class composition and its capital costs, the concept of relative customer class risk is inapplicable as a basis for setting customer class target rates of return within the framework of a cost of service study such as the ECOSS submitted by the Utilities in this proceeding. Therefore, the Commission accepts and approves the Utilities' rate of return proposals as fair and reasonable.

IX. RATE DESIGN

A. Overview

(This account, provided by the Utilities outlines the scope of this Part of the Order).

The Utilities have not filed a rate case since 1995, and the current tariff book was created that year. The tariff books that the Utilities submitted in these proceedings, they point out, are completely new and have been submitted as IL.C.C No. 28 and IL.C.C

No. 17 for Peoples Gas and North Gas, respectively. PGL Ex. VG-1.1 and NS Ex. VG-1.1.

In designing rates, the Utilities maintain that they have sought to accomplish six major objectives. These are to: (1) better align costs and revenue recovery; (2) provide more equity between and within rate classes; (3) maintain rate design continuity; (4) reflect gradualism; (5) retain customers on the Utilities' systems; and, (6) consolidate certain transportation riders while providing new service options for transportation customers. PGL Ex. VG-1.0 REV at 4; NS Ex. VG-1.0 2REV at 4.

The Utilities explain that they have presented analyses that reflect their revenues under present and proposed rates with Rider UBA. *See* PGL Ex. VG-1.1; NS Ex. VG-1.2. These exhibits also reflect the proposed transportation diversity factors of .87 and .75 for transportation customers of Peoples Gas and North Shore, respectively. *See*, PGL Ex. VG-1.0 REV at 5; NS Ex. VG-1.0 2REV at 5; and PGL Ex. VG-1.2, 1; NS Ex. VG-1.2, 1. The Utilities have submitted additional exhibits which show rate and revenue impacts with Rider UBA expenses recovered through base rates, rather than through a rider mechanism. *See* PGL Ex. VG-1.0 REV at 5; NS Ex. VG-1.0 3REV at 5; and PGL Ex. VG-1.2, page 2 and NS Ex. VG-2.1, page 2. Rider UBA places recovery of the gas cost portion of uncollectible expense in a rider rather than base rates. If the Commission does not approve this proposal, the Companies' base rates must include the full uncollectible expense. Accordingly, the Companies' rate and revenue data reflect the preferred rate design, which includes Rider UBA as well as rate and revenue data with uncollectible expense in base rates without Rider UBA.

The Utilities explain that they have utilized Mr. Amen's ECOSS as the basis for the determination of the revenue requirement and resulting proposed rates in this proceeding, including the analyses without Rider UBA. They used the ECOSS to move rates toward cost-based rates and to better align charges with like costs. The ECOSS was also used as the basis for bifurcating Service Classification No. 1 into two new service classifications: S.C. No. 1N, Small Residential Non-Heating Service, and S.C. No. 1H, Small Residential Heating Service. PGL Ex. VG-1.0 REV at 6; NS Ex. VG-1.0 3REV at 6. Utilizing the ECOSS results which determine the cost of service for each service classification, North Shore proposes to continue to set all its service classifications at cost. Peoples Gas proposes to set all service classifications, except S.C. Nos. 1N, 1H, and 2, at cost. The remaining revenue requirement for S.C. Nos. 1N, 1H and 2, is allocated utilizing the equal percentage of embedded cost ("EPEC") methodology (discussed in more fully in section B(1) of this Section IX).

Almost all of the Utilities' costs, about 95% for Peoples Gas and about 98% for North Shore are fixed, i.e., they do not vary with throughput, and the Utilities have traditionally recovered a greater portion of their costs through non-fixed volumetric charges. The Utilities' last rate case filed about 12 years ago reflected costs that were 98% and 97% fixed for Peoples Gas and North Shore, respectively. Less than 30% of fixed costs were recovered through fixed charges. *See*, Dockets Nos. 95-0031 and 95-0032. This mismatch of fixed costs and non-fixed charges practically assures that the Utilities will either over or under-earn their Commission approved revenue requirement and that customers will either over or under pay their share of such costs. To partially remedy this, the Utilities are proposing to recover more fixed costs through fixed charges. PGL Ex. VG-1.0 REV at 8-9; NS Ex. VG-1.0 3REV at 6-7.

Generally the Utilities have proposed to increase customer charges in an effort to recover more fixed costs in the fixed charge. The relative increase in customer charges proposed by the Utilities is consistent with a growing trend whereby public utility commissions have approved greater fixed cost recovery in fixed charges. This trend has resulted in the approval of rate models where all fixed cost are recovered through a fixed charge, such as the Straight Fixed Variable "SFV" rate design or customers paying a largely flat charge for utility delivery service, with little or no volumetric charge. *See* Re Atlanta Gas Light Company*,* 2001 WL 1776861 (Ga. P.S.C., Sep 18, 2001) (Docket. No. 8516-U). Greater fixed cost recovery through customer charges stabilizes the non-gas cost delivery charge portion of customers' bills and stabilizes the variability in earnings related to variations in customer consumption caused by weather and other conditions outside the Utilities' control. While the Utilities maintain that an SFV rate design would be the optimal one, PGL Ex. VG-1.0 REV at 17; NS Ex. VG-1.0 3REV at 14, they are proposing only to recover a greater portion of fixed cost through increased customer charges.

The particulars of the rates and rate design proposals of the Utilities and other parties are discussed below.

Generally, as to Peoples Gas, the Company has proposed ten major changes to its base rates and other charges. These are the following.

1. S.C. No. 1, Small Residential Service, will be bifurcated into two service classifications: S.C. No. 1N, Small Residential Non-Heating Service, and S.C. No. 1H, Small Residential Heating Service.

2. The monthly customer charge for S.C. No. 1N customers will be increased. The distribution charge, which is a two-block rate structure under current S.C. No. 1, will become a flat charge.

3. The monthly customer charge for S.C. No. 1H customers will be increased. The distribution charge will reflect a decrease in the end block with a greater percentage of costs being allocated to the front block of the current two-block rate structure.

4. The monthly customer charges for each Meter Class under S.C. No. 2, General Service, will be increased. The distribution charge will reflect an increase in the front and middle blocks and a decrease in the end block of the three-block rate structure.

5. S.C. No. 3, Large Volume Service, and S.C. No. 4, Large Volume Demand Service, will be combined under S.C. No. 4. S.C. No. 3 will be eliminated. The monthly customer charge and demand charge will be decreased. The distribution charge and standby service charge will be increased. This service classification is set at cost.

6. The monthly customer charge and distribution charge for S.C. No. 6, Standby Service, will be increased. The demand charge will be decreased and

will reflect a single demand charge rather than the separate demand charges for heating and non-heating customers under current rates. This service classification is set at cost.

7. The customer charge and distribution charge for S.C. No. 8, Compressed Natural Gas, will be increased. This service classification is set at cost.

8. Service reconnection charges and service activation charges will be restructured to reflect a base charge and charges for additional appliances.

9. The Charge for Dishonored Checks and/or Incomplete Electronic Withdrawal will be increased to better reflect prevailing rates for such checks and transactions and to discourage customers from making such deficient payments to the Company.

10. The Company is proposing a new charge for a Second Pulse Data Capability to accommodate customers' requests for this service.

See PGL Ex. VG-1.0 REV at 9-10.

Generally, as to North Shore, the Company has proposed nine major changes to its base rates and other charges. These are the following.

1. S.C. No. 1, Small Residential Service, will be bifurcated into two service classifications: S.C. No. 1N, Small Residential Non-Heating Service, and S.C. No. 1H, Small Residential Heating Service.

2. The monthly customer charge for S.C. No. 1N customers will be increased. The distribution charge, which is a two-block rate structure under current S.C. No. 1, will become a flat charge. This service classification is set at cost.

3. The monthly customer charge for S.C. No. 1H customers will be increased. The distribution charge will reflect a decrease in the end block with a greater percentage of costs being allocated to the front block of the current two-block rate structure. This service classification is set at cost.

4. The monthly customer charges for each Meter Class under S.C. No. 2, General Service, will be increased. The distribution charge will reflect an increase in the front and a decrease in the middle and end blocks of the three-block rate structure. This service classification is set at cost.

5. The monthly customer charge, distribution charge, demand charge and standby service charge for S.C. No. 3, Large Volume Service will be decreased. The increased. The demand blocks for this service classification will be changed from 5,000 therms and over 5,000 therms to 10,000 therms and over 10,000 therms. This service classification is set at cost.

6. The monthly customer charge and distribution charge for S.C. No. 5, Standby Service, will be increased. The demand charge will be decreased. This service classification is set at cost.

7. Service reconnection charges and service activation charges will be restructured to reflect a base charge and charges for additional appliances.

8. The Charge for Dishonored Checks and/or Incomplete Electronic Withdrawal will be increased to better reflect prevailing rates for such checks and transactions and to discourage customers from making such deficient payments to the Company.

9. The Company is proposing a new charge for a Second Pulse Data Capability to accommodate customers' requests for this service.

See Ex. VG-1.0 REV at 7-9.

The Utilities indicate that only certain of these proposals are contested. Here, the Commission begins to consider and discuss the entirety of the proposals.

B. General Rate Design

1. Allocation of Rate Increase

a) The Utilities

North Shore proposes to continue to set all its service classifications at cost. Peoples Gas proposes to set S.C. Nos. 4, 6 and 8 at cost and to allocate the remaining revenue requirement among S.C. Nos. 1N, 1H and 2 utilizing the equal percentage of embedded cost (EPEC) method. The EPEC method allocates the remaining revenue requirement in proportion to the embedded costs of service for these three service classifications and the resulting amounts are added to the revenue generated under currently applicable rates for the particular service classification to arrive at the revenue to be provided under proposed rates. PGL Ex. VG-1.0 REV at 6; NS Ex. VG-1.0 3REV at 6.

According to the Utilities, the EPEC method provides a gradual movement toward full cost recovery for the small residential customer service classifications. It also provides a gradual movement toward equalizing rates of return for these service classifications. PGL Ex. VG-1.0 REV at 7. It would appear that all parties support the notion that, ideally, all service classifications should support their full cost of service.

Indeed, the Utilities assert, all service classifications should support their full cost of service. For various historical and policy reasons, however, the rates of Peoples Gas' small residential service classification have been set below costs. In order to avoid the rate spikes that would attend moving residential service classifications to costs, Peoples Gas contends that it has applied a policy of gradualism in the movement toward full cost and the Commission has heretofore endorsed this gradualism in its approval of the EPEC method. *See* Peoples Gas Light and Coke Co., Docket Nos. 91-0586 and 95-0032.

While no party appears to quarrel with the notion of gradualism being employed in these proceedings, the Utilities observe that two of the witnesses appear to take issue with the rate increase allocations that result from application of the EPEC mechanism. According to the Utilities, however, no other party has proposed a method that is definable and supportable, like the EPEC methodology, although a third party offers a vague alternative to Peoples Gas' proposal. If anything, the Utilities argue, the rate increase allocation proposals for Peoples Gas by other parties appear to have been arbitrarily derived and none have been accompanied by analysis which would show the impact of their proposals on customers' bills. In short, only Peoples Gas has provided a reasoned and specific analysis to support its rate increase allocation and only the Companies have shown how their specific rate proposals would affect customers.

b) AG

The AG notes the Utilities to propose using the Equal Percent of Embedded Cost ("EPEC") method of allocating the approved revenue requirements in this case. As such, the Utilities propose to set S.C. Nos. 4 (Large Volume Service), 6 (Standby Service) and 8 (Compressed Natural Gas service) to cost. PGL Ex. VG-1.0 at 6. The remainder of the rate increase, i.e., $72.9 million, is to be allocated among the residential and small business rate classes, S.C. 1 Non-heating, 1 Heating and 2 General Service. PGL Ex. VG-1.3.

The AG observes Utilities' witness Grace to assert that the EPEC method used by the Utilities "moves the small residential service rates closer to cost in a gradual manner." PGL Ex. VG-1.0 at 7. In the AG's view, however, the proposed rate design in this case, which includes a doubling of the customer charge forPeoples Gas's residential customers and an 88 percent increase for North Shore's residential customers, belies this assertion. In addition, the AG sees no real explanation to be given for combining the Rate 2 class (which serves commercial and some industrial customers).

According to the AG, Mr. Glahn identified several problems with the Utilities' application of the EPEC methodology. He observed that instead of equalizing rates across all service classifications, the Utilities chose to equalize rates across arbitrary subgroups, and in doing so, they propose disparate increases among various customer classes that do not meet sound rate design criteria. GCI Ex. 1.0 at 12. Mr. Glahn also observed that the proposed allocated revenue increase raises the cost recovery percentage of most classes, however, the business classifications "are not treated remotely the same", and this violates the principle of horizontal equity, i.e. that equals be treated equally. Id. He notes that S.C. 2 gets an increase of almost 22 percent, but S.C. 3 gets an increase of only 14 percent and S.C. 4 receives an increase of less than one-tenth that size at 2.12 percent. Id. at 12,13. As shown in VG-1.3, page 2, the AG notes, S.C. 4 would continue to pay less than its assumed cost of service, while S.C.2 would go from slightly below cost to more than 21 percent above cost. Id.

Moreover, the AG points out that, despite being grouped with S.C.6 and 8, S.C. 7 is allocated none of the increase because, according to Ms. Grace, the revenues from S.C.7 are based on negotiated, contract rates. Id. at 13, citing PGL Ex. VG-1.0 at 8. The AG argues that Mr. Glahn was correct to note that regardless of how prices are determined for members of S.C. 7, there is a cost to serve these customers in that these customers use the same system facilities and services as all of the other S.C. customers. GCI Ex. 6.0 at 8. As such, the AG asserts, some of the increases in costs that the Company alleges have occurred should be imputed to S.C. 7 customers. And, whether the Utilities elect to recover these additional costs from S.C.7 customers is up to them. Id. at 9.

Instead of the Utilities' arbitrary groupings, the AG maintains that the Commission should adopt Mr. Glahn's modified version of the utilities' methodology that is more akin to an equal percentage of revenue increase, as detailed in GCI Ex. WLG-3.1, Schedule 2. The AG explains that Mr. Glahn's methodology would be applied across all service classifications, without regard to the PGL-NS sub-groupings. GCI Ex. 3.0 at 14. In order to achieve more fairness and equity across the rate classes, Mr. Glahn set S.C. Nos. 6 and 8 at their assumed cost of service, as the Utilities did. But, he recommends imputing an increase of 26.6 percent (the average system increase) to S.C.7, to reflect the increase in the cost to serve these customers. Id.

To achieve horizontal equity, the AG observes that Mr. Glahn assigned the three business rate classes, Nos. 2, 3 and 4, the same percentage increase of 21 percent, which is far less than the average 26.6 percent increase for all rate classes. Id. He noted that having all three receive the same percentage increase in revenues preserves the horizontal equity of these groups, but in setting their increases at less than the Utilities' average moves two of these classes toward their cost of service. Id. Mr. Glahn noted that this approach still leaves S.C. 2 paying 121 percent of assumed costs, while having S.C.3 pay only 107 percent and S.C.4 pay 116 percent. Id. As Mr. Glahn explained, this result appears much more equitable than having the business customers in S.C.2 paying 121 percent of cost, while business customers in S.C.4 paying only 98 percent. Id.

For the two S.C.1 designations, the AG notes, Mr. Glahn recommended that non-heating customers allocated the same dollar amount as allocated by Utilities' witness Grace in her Exhibit VG-1.2, page 2, with the remaining increase going to heating customers. Id. He testified that this allocation improves horizontal equity by moving the two subgroups closer together. Id. at 14-15.

The AG observes Utilities' witness Grace to have stated that Rate 4 customers must "be set at cost." PGL-NS Ex. VG-2.0 at 16. Mr. Glahn noted, however, that the testimony of Mr. Amen indicated that S.C. 2 includes "many relatively large customers", including one large industrial customer that was formerly a member of S.C.7 (Contract Rates for Bypass Service). GCI Ex. 6.0 at 9. So, Mr. Glahn observed that S.C.2 includes at least one large customer that has an "economically feasible and practical" ability to bypass the system. Id. Yet, Mr. Glahn pointed out, Peoples Gas sees fit to impose upon that customer and others in S.C.2 rates equal to 124 percent of their cost of service. Id.

The AG maintains that Mr. Glahn's proposed revenue increase allocation for these classes is less arbitrary than what the Company proposes, comports with principles of fairness and equity, and should be adopted.

c) City-CUB

City-CUB observe that Peoples Gas' various rate classes, other than S.C. 2, are not currently at their respective cost of service levels, as the Utilities would propose. GCI Ex. 3.0 REV. at 11. To move the utility's classes closer to cost of service, they note that the Utilities propose moving Peoples Gas S.C. Nos. 4, 6 and 8 to cost, and then apportioning the remaining portion of the proposed revenue requirement – $72.9 million, for Peoples Gas – among S.C. Nos. 1N, 1H and 2 using the EPEC method. The EPEC method, they explain, allocates the increase portion of the proposed revenue requirement based on the class's proportion of embedded costs to total embedded costs. PGL Ex. VG-1.0 REV. at 6. And, the City-CUB note Peoples Gas to assert that this approach "provides a gradual movement" toward equal class rates of return. Id. at 7. Although City-CUB agree that gradualism and equity are laudable goals, they maintain that the utility's proposed allocation of the Peoples Gas rate increase nonetheless should be adjusted as recommended by Mr. Glahn to more equitably apportion the increase.

According to City-CUB, the Utilities' allocation proposal violates the principle of horizontal equity, i.e., that equals should be treated equally, by treating Peoples Gas' business classifications differently. They observe that the proposed allocation results in an increase of almost 22 percent in rates for its S.C. No. 2 customers, but only a 14 percent increase for S.C. 3 customers, and just a 2.12 percent increase for S.C. 4 customers. GCI Ex. 3.0 REV. at 12-13. As Mr. Glahn explained, this inequitable allocation is the result of the Companies' arbitrary grouping of the service classifications: with S.C. 1 and 2 in the first group; S.C. 3 and 4 in the second; and S.C. 6, 7 and 8 in the third. Id. at 13.

City-CUB observe that Ms. Grace discussed the reasons for using the EPEC method to allocate the rate increase among the "small residential" classes – S.C. 1N and 1H – and for proposing to consolidate S.C. Nos. 3 and 4. *See* PGL Ex. VG-1.0 REV. at 7-8. As to the EPEC method, she maintained the Companies used it to move "S.C. Nos. 1N and 1H toward their respective revenue requirements on a gradual basis." Id. at 7. According to City-CUB, this testimony fails to explain why Peoples Gas has grouped S.C. 2 (the general service class) with S.C. 1N and 1H (both small residential classes) in allocating the utility's proposed rate increase. Similarly, City-Cub observe, her stating that S.C. 3 and 4 should be combined because the difference in average load factors between the two classes has "significantly narrowed" does not explain why these two business classes were not grouped with S.C. 2 in apportioning the rate increase. Id. at 24.

City-CUB observe that Ms. Grace's discussion of the differences in the average annual loads and rate structures of S.C. 2 and S.C. 4 does not explain why S.C. 2 was grouped with small residential customers rather than with S.C. 3 and 4. *See* NS-PGL Ex. VG-3.0 at 6-7. Also missing, in their view, is any comparison of the respective differences in average annual loads and rate structures between S.C. 2 and S.C. 4 on the one hand, and between S.C. 2 and S.C. 1N and 1H on the other. According to City-CUB, the Utilities have not shown that S.C. No. 2 is more similar in terms of annual load to S.C. Nos. 1N and 1H than to the combined S.C. No. 4, and therefore should be grouped with S.C. 1 rather than S.C. 4. Indeed, they note Ms. Grace to concede that there are "some large volume load customers" in S.C. 2, id. at 6, including the electric power plant identified by Mr. Amen. Id. at 6-7; NS-PGL Ex. RJA-2.0 at 17.

Another flaw that City-CUB perceives in the Utility's proposed allocation of the rate increase is that, while it is grouped with S.C. 6 and 8, S.C. 7 is not allocated any of the increase. Peoples Gas asserts this omission is appropriate because "the revenues from customers served under this service classification are based on a negotiated [contract] rate rather than the cost of service analysis filed in this case." PGL Ex. VG-1.0 3REV. at 8. Mr. Glahn, however, testified that "[r]egardless of how prices are determined for members of Service Classification No. 7, there is a cost to serve these customers." GCI Ex. 3.0 REV. at 13.

City-CUB observed Ms. Grace to have countered that: (a) the contracts for customers served under S.C. 7 are limited to five-year terms, and have been renegotiated "based on the proper cost considerations," and cannot be modified to include a portion of the proposed rate increase; (b) Mr. Glahn did not explain how Peoples Gas would recoup revenue from contracts that are not renewed because of actual bypass; and, (c) revenues arising from S.C. No. 7 "contribute to recovery of Peoples Gas' fixed costs and mitigate any increase on Peoples Gas' system customers." NS-PGL Ex. VG-2.0 at 17. In the City-CUB's view, these responses do not rebut, or even address, Mr. Glahn's fundamental argument that S.C. No. 7 customers use the same system facilities and services as customers in other service classifications, and the cost of building, operating and maintaining those facilities and services has risen since the Companies' last rate case. *See* GCI Ex. 6.0 REV. at 8-9. They maintain that Ms. Grace's vague reference to purportedly "proper cost considerations" and the claim that S.C. 7 customers contribute to recovery of distribution costs should not distract the Commission from observing that Peoples Gas allocated none of its proposed rate increase to S.C. 7.

As to the mechanics of recovering a portion of the rate increase from S.C. No. 7, City-CUB note that the Utilities have not stated whether their contracts with S.C. 7 customers include a provision for incorporating supervening changes in the Companies' rates approved by the Commission – and if not, why this is so. To the extent the Utilities did not include such a provision in the contracts, City-CUB believe that omission should not serve as a basis for shifting S.C. 7 cost increases to other customer classes through the allocation process. In any event, they argue, whether and how Peoples Gas chooses to recover those additional costs from S.C. No. 7 customers is up to the utility. Id. at 9.

City-CUB point out that by taking well established equity principles into account, Mr. Glahn proposed an alternative allocation of the revenue increase, more akin to an "equal percentage of revenue increase." GCI Ex. 3.0 REV. at 14. In particular, he set S.C. 6 and 8 at their assumed cost of service, as Peoples Gas did, but imputed the average system increase (26.6 percent) to S.C. 7, to reflect the increase in the cost of serving customers in that class. Like Peoples Gas's proposed allocation to S.C. 1N and 1H, Mr. Glahn's alternative allocation would, in the interest of gradualism and equity, move these residential classes closer to, but not entirely to, their cost of service levels. To better serve horizontal equity, however, Mr. Glahn allocated the same 21% increase to S.C. 2, 3 and 4, moving S.C. 2 to 121 percent of cost and S.C. 3 and 4 to 107 percent and 116 percent above cost, respectively.

This, the City-CUB argue, is a more equitable allocation for the business classes than having S.C. 2 at 121 percent of cost, while having the combined S.C. 3 and 4 class at cost, as Peoples Gas proposes. Id. at 14-15. Moreover, they consider Ms. Grace's claim, that it is important to set S.C. 4 at cost because customers in that class may be able to bypass Peoples Gas's system (NS-PGL Ex. VG-6.0 REV. at 16), to not undermine the basis for Mr. Glahn's proposal to move S.C. 4 above cost, given that both his proposed allocation, and that of Peoples Gas, would move S.C. 2 considerably above cost. According to City-CUB, to increase S.C. 2 rates above cost while setting combined S.C. 4 rates at cost (simply for the reason that S.C. 2 customers do not have the same ability to physically bypass Peoples Gas' system) is patently unfair.

In City-CUB's view, Peoples Gas' allocation of its proposed rate increase violates the principle of horizontal equity by treating business customers in S.C. 2 and combined S.C. 4 differently. In addition, the utility has improperly failed to allocate to S.C. 7 any of the increase in the cost to serve that class. Mr. Glahn's alternative allocation more equitably apportions the rate increase among Peoples Gas S.C. 2 and combined S.C. 4 and properly imputes a portion of the proposed rate increase to S.C. 7. Accordingly, the Commission should reject Peoples Gas's proposed rate increase allocation and instead adopt Mr. Glahn's alternative allocation.

It is unclear to City-CUB why, in apportioning its proposed rate increase, Peoples Gas grouped S.C. 2, the general service class, with S.C. 1N and 1H, both small residential classes, rather than with S.C. 3 and 4. Although to justify this grouping, Ms. Grace pointed to differences in average annual loads and rate structures of S.C. 2 and 4 (*see* NS-PGL Ex. VG-3.0 at 6-7), City-CUB claim that she did not compare the respective differences between S.C. 2 and S.C. 4 on the one hand, and between S.C. 2 and S.C. 1N and 1H on the other. As such, City-CUB argue, the Utilities have not shown that S.C. No. 2 is more similar in terms of annual load to S.C. Nos. 1N and 1H than to the combined S.C. No. 4. therefore should be grouped with S.C. 1 rather than S.C. 4.

City-CUB contend that the Companies ignore Mr. Glahn's specific alternative allocation of the revenue increase, which is more akin to an "equal percentage of revenue increase." GCI Ex. 3.0 REV. at 14. In particular, Mr. Glahn set S.C. 6 and 8 at their assumed cost of service, as Peoples Gas did, but imputed the average system increase (26.6 %) to S.C. 7, to reflect the increase in the cost of serving customers in that class. To better serve horizontal equity, Mr. Glahn allocated the same 21% increase to S.C. 2, 3 and 4, moving S.C. 2 to 121 percent of cost and S.C. 3 and 4 to 107 percent and 116 percent above cost, respectively. According to City-CUB, this is a more equitable allocation for the business classes than having S.C. 2 at 121 percent of cost, while having the combined S.C. 3 and 4 classes at cost, as Peoples Gas proposes. Id. at 14-15. Nor should the Commission be distracted by the Companies' sweeping misstatement that other parties' alternatives to Peoples Gas's proposed alternatives to the utility's rate increase allocation were "arbitrarily derived." PGL-NS Init. Br. at 159.

According to City-CUB, Peoples Gas's allocation of its proposed rate increase violates the principle of horizontal equity by treating business customers in S.C. 2 and combined S.C. 4 differently. In addition, the utility has improperly failed to allocate to S.C. 7 any of the increase in the cost to serve that class. GCI's alternative allocation, which more equitably apportions the rate increase among Peoples Gas S.C. 2 and combined S.C. 4, also imputes a portion of the proposed rate increase to S.C. 7. Accordingly, the Commission should reject Peoples Gas's proposed allocation of its rate increase and instead adopt GCI's alternative allocation.

d) Utilities Response

The Utilities observe that no party appears to quarrel with the notion of gradualism being employed in these proceedings. They note, however, that two of the witnesses appear to take issue with the rate increase allocations that result from application of the EPEC mechanism. Nevertheless, the Utilities point out, no party has proposed a method that is definable, supportable, and reasonable like the EPEC methodology (although one party does set out a vague, but interesting alternative to Peoples Gas' proposal).

The Utilities observe Staff witness Luth to take issue with certain aspects of the Peoples Gas allocation of the proposed rate increase to customer classes. Mr. Luth proposes specific rates for S.C. Nos. 1N and 1H as well as a specific amount of the remainder of the S.C. Nos. 1N and 1H increase that would be allocated to S.C. No. 2 based on the revenue requirement that he determined. According to the Utilities, however, Mr. Luth's methodology for this allocation is flawed. His proposal is driven by specific charges for S.C. Nos. 1N and 1H, and a specific amount for the increase that would be allocated to S.C. No. 2, rather than an overarching method that could be readily and objectively applied to a revenue requirement that would differ from his own. While Mr. Luth achieves rate outcomes that may not be unreasonable, the Utilities observe that his methodology is not capable of being applied predictably and readily to the revenue requirement that will ultimately be determined in this Order.

For his part, the Utilities observe that Mr. Glahn's sole basis for criticizing the EPEC method is his belief that it applies arbitrary customer class groupings. The Utilities note, however, that Mr. Glahn never explains why he believes these customer class groupings under the EPEC are arbitrary. Instead, he simply recites the revenue cost ratio effect of the EPEC method and proceeds to inappropriately allocate additional costs to one service classification (S.C. No. 4), which is set at cost, and to another service classification, (S.C. No.7), where contractually set rates already reflect the appropriate cost considerations. The Utilities maintain that Mr. Glahn ignores the purpose of the groupings, which is simply to employ the EPEC methodology, and to set S.C. No. 4 (which combines two similar service classifications) at cost. The Utilities point out that Ms. Grace explains in detail, and on record, why S.C. No. 4 should be set at cost and why Mr. Glahn's proposal for S.C. No. 7 is not appropriate.

Finally, the Utility points out, Mr. Glahn's methodology is mathematically incorrect and results in an increase which is $533,971.00 higher than what has been proposed by Peoples Gas. *See* NS-PGL Ex. VG-2.2, pg. 1, columns A and D and GCI Ex. 3.0, Ex. WLG-D, Schedule 2, column (4). And, where both Peoples Gas and Staff support setting S.C. No. 4 at cost, Mr. Glahn alone supports setting S.C. No. 4 over cost or allocating costs to S.C. No. 7. In the Utility's view, Mr. Glahn's S.C. Nos. 4 and 7 proposals are even more problematic because he inappropriately allocates additional costs to these service classifications, and offers no specific rate design proposals for either one.

The Utility observes that Neil Anderson, on behalf of Vanguard, proposes to phase in increases for rate classifications to reach cost over a five (5) year period. His proposal, however, is devoid of details. While Mr. Anderson characterizes his proposal as a rate design proposal, he does not offer any rates or meaningful rate design proposal for any service classification. His exhibit (VES Ex. 3), which supports his “rate design proposal”, reflects revenue allocations for years 1 through 4 that are consistent with Peoples Gas’ EPEC revenue allocation. It is unclear to the Utility as to how the revenue allocation in year 5 (VES Ex. 3, line 9) was derived. And, it should be noted that the service class revenues in year 5 (id.) do not sum to the total company revenues and the total revenue amount is not consistent with any revenue amount proposed by any party in this proceeding. Peoples Gas agrees that it is appropriate to move all service classifications to cost, and it is taking significant steps in this case, including bifurcating S.C. No. 1 into heating and non-heating rates, to move S.C. No. 1 to cost. *See*, NS-PGL Ex. VG-2.0 at 17-18. In the end, however, Mr. Anderson’s proposal lacks sufficient detail for the Commission to evaluate and should be rejected.

Indeed, the Utility argues, the rate increase allocation proposals for Peoples Gas by other parties appear to have been arbitrarily derived or are improper and none have been accompanied by analysis which would show the impact of their proposals on customers’ bills. As such, only Peoples Gas has provided a reasoned and specific analysis to support its rate increase allocation and only the Companies have shown how their specific rate proposals would affect customers.

e) Commission Analysis and Conclusion

At this juncture, Peoples Gas has proposed to allocate a portion of the S.C. No. 1N and 1H rate increases to S.C. No. 2 by utilizing the EPEC method. We understand that this methodology, mechanical and objective, is not based upon any specific rates or rate design proposals. Instead, it is based upon a defined formula approved in Peoples Gas’ two prior rate cases which determines the amount of the small residential service classification rate increase that will be allocated to the S.C. No. 2 revenue requirement. In addition to being precedential, the utilities most definitively explain, there are sound reasons for Peoples Gas to use the EPEC method. NS-PGL RBOE at 36. First, they note Peoples Gas witness Grace explained that the EPEC was applied to S.C. Nos. 1N, 1H and 2 in order to move the two small residential service classifications gradually to cost. PGL Ex. VG 1.0 2REV at 11. Second, S.C. Nos. 3 and 4 were grouped, and proposed to be consolidated, because these two service classifications serve large volume customers with increasingly similar load factors. Id. at 24. Thus, unlike S.C. No. 2, S.C. Nos. 3 and 4 were, and S.C. No. 4 would continue to be, fully unbundled. NS-PGL Ex. VG-2.0 at 16. This distinction highlights the flaw in the GCI’s proposed grouping of S.C. Nos. 2 and 4 on the grounds of “horizontal equity.” The principle of horizontal equity is to treat equals as equals but, Peoples Gas asserts, S.C. No. 2 is unlike S.C. No. 4 and should not be treated the same. Id. at 11-12. Third, Peoples Gas points out GCI incorrectly state that S.C. Nos. 6, 7 and 8 were grouped. AG BOE at 48;

City-CUB BOE at 55. The Utilities maintain that they presented each of these service classifications separately in both testimony and exhibits. NS-PGL Ex. VG-2.0 at 11. Considering all the matters of record, the Commission finds that the method employed by Peoples Gas assures that the revenue requirement set forth in this Order will be readily and objectively allocated.

At the same time, the Commission is unable to ascertain if Mr. Luth's methodology would readily adapt to a revenue requirement that differs from his own. Similarly, we view Mr. Glahn's proposals for allocating the rate increase for Peoples Gas as too limited in scope and not based on a broadly applicable methodology. It appears that Mr. Glahn would arbitrarily assign an amount of the increase to S.C. Nos. 4 and 7 and without sufficient reasoning to support the assignment. In the case of S.C. No. 7, we specifically note, customers receive service under binding negotiated contracts, and it is not clearly established how such costs could be factored into these contracts. Moreover, Peoples Gas indicates that such contracts reflect the proper cost considerations and while Mr. Glahn raises the issue, he has not shown otherwise. We are further unpersuaded by Mr. Glahn in that he offers no reason why S.C. No. 4 should be set above cost, where the record demonstrates that these customers have some ability to bypass Peoples Gas' system.

In their exceptions, the GCI continued to criticize setting S.C. No. 4 at cost and allocating no cost to S.C. No. 7. Peoples Gas responds and further explains why it is important and beneficial to all customers to set S.C. No. 4 at cost. These are large volume customers, Peoples Gas says, and the service classification is only available to customers with average monthly usage of at least 41,000 therms. PGL Ex. VG-1.1 at 9. Setting this rate over cost could induce these customers to physically or economically bypass Peoples Gas' system. Since its last rate case, Peoples Gas states that the number of such large volume customers has declined significantly and additional losses of such customers would reduce fixed cost recovery. Given that Peoples Gas' costs are overwhelmingly fixed, this would result in higher rates for the remaining customers. NS-PGL Ex. VG-2.0 at 16, 24.

We see no merit to the AG's exceptions claim that S.C. No. 4 rates would be less than its allocated cost. AG BOE at 47. Peoples Gas clarifies that it proposes to combine current S.C. Nos. 3 and 4 into a single service classification to be called S.C. No. 4 and to set S.C. No. 4 at cost. Exhibits that show current S.C. No. 3 at 100.9% of cost and current S.C. No. 4 at 98% of cost combine to show the proposed S.C. No. 4 is at cost. NS-PGL Ex. VG-2.0 at 15-16.

The Commission also finds it reasonable to allocate a portion of the rate increase for S.C. No. 1 to S.C. No. 2 using the EPEC method proposed by Peoples Gas. While Mr. Anderson's proposal raises some interesting ideas in this area, at bottom, the Commission is unable to analyze his concepts for lack of sufficient detail.

2. Gas Cost Related Uncollectible Expense

a) Utilities

According to the Utilities, the only contested issue that concerns Gas Cost Related Uncollectible Expense arises from a rate design perspective centered around how the gas cost related uncollectible expense would be recovered in base rates when Rider UBA is not approved.

They note that Staff witness Luth is the only party who has taken issue on the record with the Utilities' proposals for the treatment of uncollectible expense if Rider UBA is not adopted. At one point, Mr. Luth had urged that uncollectible expense should be allocated to S.C. Nos. 3 and 4 and Peoples Gas performed an analysis that indicated a portion of bad debt was attributable to S.C. No. 3 and modified the proposals to allocate an appropriate amount to S.C. No. 4. *See* NS-PGL RJA-2.0 at 14.

Ms. Grace and Mr. Luth agree in principle that if Rider UBA is not approved, separate base rates will need to be established for sales and transportation customers. For her part, Ms. Grace has proposed an approach whereby the Utilities' ECOSS, which already reflects the removal of gas cost related bad debt expense, would establish the base rates for all customers, including transportation customers. The Gas Cost Related Uncollectible Expense would then be added to sales customer's base rates, thereby establishing separate rates in a straightforward and simply manner. According to the Utilities, Exhibits VG-2.3-PGL and VG-2.3-NSG illustrate this simple methodology which determines how the Utilities' distribution base rates would be affected. Ms. Grace's approach also allocates uncollectible expenses at full costs to each affected service classification. NS-PGL Ex. VG-2.0 at 21. This is an appropriate approach, the Utilities assert, because it mitigates the impact of such costs on Peoples Gas' S.C. No. 2 which has already been allocated a portion of the rate increase for S.C. Nos. 1N and it is based on cost causation. And, any claim of errors with respect to Exhibits VG 2.3-PGL and VG-2.3-NSG, is simply incorrect. The uncollectible expenses reflected in the referenced exhibits are recovered based on rate class specific historical write-offs, consistent with the approach utilized in Mr. Amen's ECOSS and by Mr. Luth to allocate total uncollectible expense in his ECOSS. Tr. at 1460; NS-PGL Cross Ex. 9 (Luth).

Additionally, the Utilities propose that final credits to transportation customers be based on the gas charge revenues and the gas cost related uncollectible expenses for sales customers as approved by the Commission in this proceeding, rather than any credit based on present rate total gas charge revenues which would inappropriately include a credit arising from transportation customers' own gas charge revenues. In the Utilities view, Mr. Luth mischaracterizes the proposal above to support his proposal for Account No. 904 expenses. While Mr. Amen correctly demonstrated that Account No. 904 expenses is a customer related cost, the Utilities explain that they have elected, at this time, to not recover these customer related costs through the customer charge in their gradualism approach of not recovering all customer costs through the customer charge. NS-PGL Ex. VG-3.0 REV at 13. Therefore, they argue, the determination to recover gas cost related bad debt through the distribution charge is warranted and reasonable.

The Utilities contend that they have also established the necessity for a different rate treatment for sales and transportation customers if Rider VBA or Rider WNA is implemented without approval of Rider UBA. They assert that gas cost related uncollectible expense under such circumstances should be made on a per customer, rather than on a per distribution therm basis. NS-PGL Ex. VG-3.0 REV16-17.

Finally, the Utilities maintain that, if Rider UBA is not approved, gas cost related uncollectible expenses should be recovered entirely through the distribution charge, rather than the customer charge and the distribution charge. Although they assert that Mr. Amen correctly demonstrated that Account No. 904 expense is a customer related cost, the Utilities elect not to recover certain costs through the customer charge in their gradualism approach of not recovering all customer costs through the customer charge. NS-PGL Ex. VG-3.0 REV at 13. They contend that this determination to recover gas cost related bad debt through the distribution charge is warranted and reasonable.

In their Brief on Exceptions, the Utilities argued that the AG's first point pertains to the amount of dollars to be allocated and is unrelated to the underlying rate design issue. The AG's second point is a criticism of the proposed bifurcation of S.C. No. 1 into a heating and non-heating service classification and is, likewise, unrelated to the underlying rate design issue. Similarly, the Utilities argued that the AG's fourth point about proper price signals would be more properly addressed in the larger context of the S.C. No. 1 rate design and not in connection with this design question for a specific cost.

The Utilities stated that the AG's third point, addressing the allocation of the uncollectible expense for S.C. No. 1H between the first and second block, ignores the fact that the Utilities' proposal for this item is consistent with its overall proposal for S.C. No. 1H. Specifically, the Utilities proposed that 67% of the expense be allocated to the front block, just as it proposed for the allocation of costs not recovered through the customer charge. PGL Ex. VG-1.0 at 14; NS Ex. VG-1.0 at 12; *also see* NS-PGL Ex. 3.0 REV at 18. There are no alternative formulaic proposals for determining distribution charges once the Commission sets the revenue requirement and the customer charge component of the service classifications. According to the Utilities, only they proposed specific methods for easily and objectively determining distribution charges, whatever revenue requirement is approved. *See, e.g.*, NS-PGL Ex. VG-3.0 REV at 5, 18, 19, 22.

b) Staff

According to Staff, part of the problem with both Rider UBA and the Utilities' alternative base rate proposal, is the application of a uniform rate to determine the recovery of uncollectible gas costs from customer service classifications subject to Rider UBA, regardless of how each customer class adds to uncollectible gas costs. Staff Ex. 19.0 at 16-17. In Staff's view, the result would be that some customer service classifications would pay more than the amount of uncollectible gas costs those customers add to uncollectible gas costs under Rider UBA or the Companies' proposed alternative recovery of uncollectible gas costs through base rates, while other customer classes would pay less than the amount that those customer classes add to uncollectible gas costs. Since the gas costs and the uncollectible rate among SC 2 customers are different from gas costs and uncollectible rate among SC 1N and SC 1H customers, Staff contends that SC 2 sales customers should pay a different amount per therm for uncollectible gas costs than SC 1N and SC 1H customers. Id. Sched. 19.3-NS and 19.3-PG, lines 5, 10, and 14.

Staff observes that sales customers in each customer service classification are supplied natural gas by North Shore or Peoples Gas, depending upon which company provides gas delivery service to the customer. Staff notes that transportation customers obtain their own supplies of gas which are then delivered by either North Shore or Peoples Gas. On the basis of this difference, Staff's view is that sales customers should pay for uncollectible gas costs, but transportation customers should not pay for uncollectible gas costs because neither North Shore nor Peoples Gas provide gas supply to transportation customers.

Staff notes that its witness Luth developed an uncollectible rate for each customer service classification that would result in the uncollectible rate for each customer service classification being applied to gas costs that each customer service classification is estimated to incur in the test year. Id. Sched. 19.3-NS and 19.3-PG. Thus, by developing a customer service classification-specific uncollectible rate, Staff contends that sales gas customers in each service classification would pay uncollectible gas costs that are based upon how customers in their own service classification affect uncollectible gas costs rather than how customers in other service classifications affect uncollectible gas costs. Staff claims to have demonstrated how the Companies' approaches yielded inconsistent results because a given customer service classification would pay different amounts for uncollectible gas costs, depending upon whether Rider UBA would be implemented or if uncollectible gas costs would be included in base rates. Id. at 16-17.

Staff argues that the Commission should reject both the proposed Rider UBA, and the Utilities' proposed alternative approach to including uncollectible gas costs in base rates. Instead, Staff urges the Commission to apply the calculations shown on Staff Schedules 19.3-NS and 19.3-PG, so that uncollectible gas costs are recovered from sales customers on a class-specific basis. The calculations that are shown on these schedules, Staff explains, would ensure that transportation customers in some customer service classifications do not overpay for natural gas delivery service while others pay less than the cost paid for natural gas delivery service compared to sales customers.

With respect to the Utilities' surrebuttal proposal to possibly bill uncollectible gas costs through the customer charge, Staff believes that under no circumstances should uncollectible gas costs be recovered through the customer charge. Gas costs are billed on a per-therm basis through the Rider 2 Gas Charge. Amounts uncollectible through therms billed under Rider 2 should not be included in the customer charge, Staff claims, because of the mismatch that would occur for amounts billed but uncollected on a per-therm basis, versus charging for the uncollectible amounts on a per-customer basis.

The Utilities' alternative proposal to recover gas costs through the distribution charge is generally appropriate and is generally in agreement with Staff's proposal, but the specifics of that proposal serve to overcharge some customers for uncollectible gas costs and do not sufficiently charge other customers. According to Staff, the defects in the Companies' proposal are perhaps most apparent with Peoples Gas SC 1N uncollectible gas costs. As such, Peoples Gas would recover $1,432,688 in uncollectible gas costs from SC 1N customers, PGL Ex. VG 2.3, column [C], line 2, but total test year gas SC 1N costs are only $14,425,000, PGL Ex. VG-1.2, page 2 of 2, column [H], line 24. $1,432,688 divided by $14,425,000 total gas costs suggests an SC 1N uncollectible rate of 9.93 percent, but the rate of uncollectible SC 1N accounts in the test year was 5.92 percent. Staff Cross-Ex. 4 (Grace), page 3 of 3, column [D], line no. 9.

Staff notes that Peoples Gas has not explained why the SC 1N uncollectible gas costs rate is 1.677 times the overall SC 1N uncollectible rate by Staff's calculation (9.93 percent divided by 5.92 percent). Other customer classes at both North Shore and Peoples Gas also show differences in the overall uncollectible accounts rate and the uncollectible gas costs rate. The reduction in the transportation distribution rate and the increase in the sales distribution rate should be calculated according to the method recommended by Staff, Staff Ex. 19.0, Schedules 19.3-NS and 19.3-PG, rather than the method suggested by the Utilities (where uncollectible gas cost rates do not agree with the overall uncollectible rates applicable to each customer service classification).

c) AG

On reply brief, the AG joins the issue. Uncollectibles are a cost of doing business, the AG notes, and arguably should be spread to all rate classes in proportion to their overall percentage of the cost.

The AG observes that the Utilities' proposal, to allocate (1) 78.7% of the uncollectible expense to Rate 1 Heating customers, and (2) then allocate 67% of the rate 1 Heating customers allocated share to the first block volumetric charge, would *trigger a nickel increase to this per therm charge solely for gas cost uncollectible expense*. PG-NS Init. Br. at 160-62. This is inequitable, the AG argues, and should be rejected.

First, the AG notes, the proposal fails to recognize the Companies agreement to reduce the test year level of uncollectibles associated with gas costs by $3.3 million in accordance with Mr. Effron's proposed adjustment. *See* PGL-NS Ex. 2.3. Second, the AG argues, the proposed rate design exacerbates the inequities of bifurcating Rate 1 customers into separate rate categories and contributes to the rate shock Residential Heating customers stand to bear if the Companies rate design proposals are approved. In the AG's view, the Utilities' proposal in this regard deviates from the rate design goals of stability and gradualism, and highlights yet another reason to not bifurcate the residential rate class.

Third, the AG contends that the allocation of 67% of the residential allocation of uncollectible expense in the first per therm volumetric block is completely arbitrary. There is no support, the AG observes in either the ECOSS or the supporting workpapers for this first-block allocation. Further, the allocation is counter-intuitive to the notion that as usage increases, uncollectibles increase. Simply put, the higher the gas bill, the more likely bad debt increases. Thus, the AG argues, the Utilities' proposal to allocate 67% of the residential heating customers' allocated cost to this first volumetric block violates cost causation principles as well.

Fourth, the AG argues, allocating the lion's share of the cost to this first volumetric block sends customers the wrong price signals regarding usage of natural gas, a nonrenewable energy source. This violates the rate design goal of conservation of resources. *See* GCI Ex. 1.0 at 7.

Instead of punishing residential heating customers with higher first block, per therm rates, and possibly contributing to increased, future uncollectible expense, the AG believes that the Commission should examine analyze this expense for rate design purposes in relation to revenues, consistent with the source of this expense. According to the AG, Schedule E-5, Section A, p. 1 provides a breakdown of revenues by customer rate class and could form the basis for allocation of the uncollectibles account expense related to purchased gas costs. (The Utilities' Rider UBA proposal trumpets the fact that the lion's share of uncollectibles costs rises as gas costs (and usage and revenues) rise.) The AG contends that this would have the effect of spreading the uncollectible expense associated with purchased gas costs across the customer rate classes. Further, the expense should be allocated on an equal percentage basis to the number of blocks within each rate class. This alternative to the Utilities' gas cost related uncollectible expense allocation, the AG argues, would satisfy the goals of gradualism, equity and fairness, conservation of resources.

In their exceptions arguments on brief, City-CUB joined in supporting the AG's position.

d) Commission Analysis and Conclusion

The Utilities and Staff address the issue of the appropriate recovery of gas cost related uncollectible expense for retail sales and transportation customers. The issue is relevant because the Commission does not approve Rider UBA. In this event, and because transportation customers do not ordinarily purchase gas from the Utilities, the gas cost related portion of uncollectible expense must be appropriately removed from the base rates.

We observe that both Mr. Luth and Ms. Grace would recover uncollectible expenses in the distribution rates. And, the respective method employed by the Utilities and Staff do not differ substantially. The Utilities believe that their method is simpler than that proposed by Mr. Luth. Nevertheless, we are informed that the Utilities would find Mr. Luth's methodology acceptable, if corrected to reflect test year gas costs and the appropriate revenues to be used in the determination of the credit for transportation customers' base rates. On this record, the Commission finds that the method for allocating gas cost related uncollectibles expense proposed by Staff is reasonable. That method will allocate the expense to Peoples Gas' S.C. Nos. 1N, 1H, 2 and 4 and North Shore S.C. Nos. 1N, 1H and 2. Further, the method should be supplemented by the corrections proposed by the Utilities.

The AG presents its views in an untimely fashion on Reply Brief. In their Brief on Exceptions, the Utilities responded to the AG's belated arguments, and the Commission finds that response persuasive. The AG's arguments are, essentially, an argument against the S. C. No. 1 rate design and not targeted to the question of the Account No. 904 expense. The Commission concluded the Utilities' S.C. No. 1 rate design was just and reasonable and, therefore, the AG's arguments are rejected.

Further exceptions arguments by City-CUB and the AG are not convincing.

C. Service Classification Rate Design

1. Uncontested Issues

a) North Shore Service Classification No. 4

(1) North Shore

The Company proposes to change the title of this service classification from "Contract Service" to "Contract Service to Prevent Bypass" so it is more descriptive. Also, it proposes to allow contract terms in excess of five years for this service classification and make minor editorial changes to the tariff language. NS Ex. VG-1.0 3REV at 23. No party or Staff opposes these proposals.

(2) Commission Analysis and Conclusion

The Commission finds the proposed changes to this service classification to be reasonable and these are accepted.

b) North Shore Service Classification No. 5

(1) North Shore

The Company's proposal is to set S.C. No. 5 at cost. Therefore, the monthly customer charge was set at $43.00. The monthly demand charge was set at 10.414 cents per therm and the distribution charge at 1.875 cents per therm. NS Ex. VG-1.0 2REV at 23. Based on his ECOSS, Staff witness Luth recommended that the Company's proposed monthly customer charge be reduced by 65 cents per month resulting in a monthly customer charge of $42.35. Staff Ex. 7.0 at 24. The Company accepts Mr. Luth's proposed adjustment as long as it is supported by the ECOSS approved in this proceeding.

(2) Commission Analysis and Conclusion

The Commission finds the proposal to set S.C. No. 5 at cost to be reasonable and the rates shall be set in accordance with the revenue requirement set forth in this Order.

c) Peoples Gas Service Classification No. 5

(1) Peoples Gas

Peoples Gas' sole proposal is to make minor editorial changes to the tariff language of SC No. 5. PGL Ex. VG-1.0 REV at 26. There has been no other proposal by Staff or by any party to this proceeding.

(2) Commission Analysis and Conclusion

The minor editorial changes proposed by the Company are here accepted.

d) North Shore Service Classification No. 6

(1) North Shore

North Shore's sole proposal is to make minor editorial changes to the tariff language of SC No. 6. NS Ex. VG-1.0 3REV at 24. There has been no other proposal by Staff or by any party to this proceeding.

(2) Commission Analysis and Conclusion

The minor editorial changes proposed by the Company are here accepted.

e) Peoples Gas Service Classification No. 6

(1) Peoples Gas

The Company's proposed changes are to set SC No. 6 at its embedded cost of service and to eliminate the distinction between heating and non-heating customers. The monthly customer charge was set at $90.00 or 80% of cost. The monthly demand charge was set at cost, 70.956 cents per therm, and the distribution charge at 14.878 cents per therm. PGL Ex. VG-1.0 REV at 26-27; NS-PGL Ex. VG-2.0 at 47-48. Staff witness Luth proposed to set S.C. No. 6 at cost although he did not make any specific rate proposals. NS-PGL Ex VG-3.0 at 27.

(2) Staff

Staff claims that the Companies Initial Brief errs in stating that Staff witness Luth did not have any specific SC 6 rate proposals. NS-PGL Init. Br. at 165. Staff agrees with the Companies' indication that Mr. Luth proposed to set SC 6 at cost, but in addition, Staff witness Luth presented SC 6 rates in his rebuttal testimony. Staff Ex. 19.0 at 20-21, Sched. 19.1-PG, p. 4 of 11, col. [F], lines 91-96; and p. 10 of 11, col. [F], lines 186-191. Staff notes that the demand charges shown for sales heating customers and transportation non-heating customers are annual rates which should be divided by 12 to arrive at a monthly charge. Id. Sched. 19.1-PG, p. 4 of 11, col. [F], lines 93-94; and p. 10 of 11, col. [F], line 190. Some of the demand charges are stated on an annual basis in part because SC 6 billing units in the Peoples Gas operating revenue schedules had been shown on an annual basis in direct testimony. NS-PGL Ex. VG-2.0 at 48. Rates for SC 6 should be set according to the cost of service developed through Staff's cost of service study, which includes the use of the A&P allocation factor for transmission and distribution system costs, adjusted to the test year revenue requirement authorized by the Commission.

(3) Commission Analysis and Conclusion

Based on what is before us, the Company's proposal to set S.C. No. 6 at cost and to eliminate the heating and non-heating distinction among S.C. No. 6 customers is reasonable and is accepted by the Commission. The rates shall be set in accordance with the revenue requirement set forth in this Order.

f) Peoples Gas Service Classification No. 8

(1) Peoples Gas

The Company proposes to increase charges under SC No. 8 to reflect its embedded cost of service. The monthly customer charge was set at $140.00 and the distribution charge was set at 5.022 cents per therm. PGL Ex. VG-1.0 REV at 27. Staff witness Luth proposed to set S.C. No. 8 at cost although he did not make any specific rate proposals. NS-PGL Ex. VG-3.0 REV at 27.

(2) Staff Reply Brief

Staff complains that the Companies Initial Brief errs in stating that Staff witness Luth did not have any specific rate SC 8 proposals. NS-PGL Init. Br. at 165. Staff agrees with the Companies' indication that Mr. Luth proposed to set SC 8 at cost, but in addition, Staff witness Luth presented SC 8 rates in his rebuttal testimony. Staff Ex. 19.0 at 20-21, Sched. 19.1-PG, p. 4 of 11, col. [F], lines 110-112. Rates for SC 8 should be set according to the cost of service developed through Staff's cost of service study, which includes the use of the A&P allocation factor for transmission and distribution system costs, adjusted to the test year revenue requirement authorized by the Commission.

(3) Commission Analysis and Conclusion

Staff's position is set out in its Reply Brief and has been considered. In these premises, we are compelled to find that the Company's proposal to set S.C. No. 8 at cost is reasonable and accepted by the Commission. The rates shall be set in accordance with the revenue requirement set forth in this Order. Staff's exceptions brief indicates no objection to our conclusion on the matter.

2. Contested Issues

a) Peoples Gas Service Classification Nos. 1N and 1H

b) North Shore Service Classification Nos. 1N and 1H

(1) Utilities

The issues pertaining to Service Classification Nos. 1N and 1H apply equally to Peoples Gas and North Shore. Therefore, they explain, the following discussion applies to both Companies.

In discussion under Section VII(B)(2)(c) hereof, the Utilities maintain that they have appropriately demonstrated a basis for bifurcating former Service Classification No. 1 into two service classifications, S.C. No. 1N and S.C. No. 1H. In this section, the Utilities discuss the specific S.C. No. 1N and S.C. No. 1H charges proposed by other parties, as well as certain S.C. No. 1N and S.C. No. 1H implementation proposals made by Mr. Luth.

North Shore has proposed to set its S.C. Nos. 1N and 1H at cost while Peoples Gas proposes to apply the EPEC methodology to allocate costs to S.C. Nos. 1N and 1H. The Utilities propose to establish the S.C. No. 1N charges for Peoples Gas and North Shore at $11.25 and $10.50, respectively. For Peoples Gas, the total monthly embedded fixed costs per customer, with Rider UBA, is $18.14 and the total monthly allocated cost per customer with Rider UBA, derived by applying the EPEC method, is $14.99. While the proposed $11.25 Peoples Gas charge represents 64% of embedded customer costs and 62% of total embedded fixed costs, the Utility explains that, by applying the EPEC method and only a portion of allocated customer costs, the increase has been limited to $2.25 per month in the interest of gradualism. Moving the charge to total allocated fixed cost would require an additional increase of $3.74 per month, while moving the charge to total embedded fixed cost would require an additional increase of $6.89 per month.

For North Shore, the total monthly embedded fixed cost per customer with Rider UBA is $16.18. The proposed $10.50 charge represents 70% of embedded customer costs and 65% of total embedded fixed costs, North Shore has limited the increase to $2.00 per month in the interest of gradualism. Moving the charge to total embedded fixed cost would require an increase of an additional $5.68 per month. PGL Ex. VG-1.0 REV at 12; NS Ex. VG-1.0 2REV at 10.

Peoples Gas is proposing to increase the monthly customer charge for S.C. No. 1H from $9.00 to $19.00 and North Shore would increase S.C. No. 1H from $8.50 to $16.00. The total embedded fixed cost per customer with Rider UBA is $36.27 and the total monthly allocated fixed cost per customer, derived by applying the EPEC method, is $33.80. While the proposed $19.00 charge represents 71% of embedded costs and 52% of total embedded fixed costs, the Utility points out that, by applying the EPEC method and only a portion of allocated customer costs, Peoples Gas has limited the increase to $10.00 per month in the interest of gradualism. Moving the charge to total allocated fixed costs would require an additional increase of $14.80 per month, while moving the charge to a total embedded fixed cost would require an additional increase of $17.27 per month. If properly aligned, the Utility asserts, such charges would be recovered entirely through a fixed monthly charge. In the interest of rate design continuity, however, Peoples Gas is proposing to recover all demand costs, as well as remaining customer costs, through the distribution charge.

Similarly, the total embedded fixed cost per customer for North Shore is $29.28. While the proposed $16.00 charge represents 55% of total embedded fixed costs and 79% of embedded customer costs, North Shore has limited the increase to $7.50 per month in the interest of gradualism. Moving the charge to total embedded fixed cost would require an increase of an additional $13.28 per month. If properly aligned, such charges would be entirely recovered through a fixed charge such as the customer charge or a demand charge. In the interest of rate design continuity, however, North Shore is proposing to recover demand costs as well as remaining customer costs through the distribution charge. PGL Ex. VG-1.0 REV at 13-14; NS Ex. VG-1.0 3REV at 11-12.

Utilities note Mr. Glahn to propose that S.C. No. 1N not be bifurcated and that Peoples Gas decrease its customer charge to $10.50, while retaining the distribution charge in Peoples Gas' currently applicable declining block rate structure. They observe that Mr. Glahn's proposed customer charge represents a slight increase in the customer charge from $9.00 to $10.50. According to the Utilities, however, his S.C. No. 1 proposal is arbitrary as Mr. Glahn offers no analysis or justification for it, except for casually comparing it to the customer charges of other Utilities. As such, Mr. Glahn has not performed a cost study for the Utilities nor has he provided any analysis of the other utilities rate designs, costs underlying their rates, or any reasoned discussion of how they have been developed or how they specifically compare with Peoples Gas' rates or why such a comparison is relevant.

The Utility contends that Mr. Glahn's proposal for North Shore's S.C. No. 1 charge is similarly flawed. In short, he proposes no bifurcation of North Shore's S.C. No. 1 charge, establishing it at its current level of $8.50. According to the Utility, however, Mr. Glahn offers no analysis to support his customer charge proposal, and he makes no attempt to address the North Shore customer charge in relation to the other components of North Shore's rates, such as the distribution charge. The Utilities submit that Mr. Glahn's North Shore proposal is, at best, incomplete.

The Utility observes Staff witness Luth to propose that Peoples Gas slightly increase its proposed S.C. No. 1N in customer charge from $11.50 to $12.00. The Utility contends that it would not be opposed to this charge as long as any change in the distribution charge is reasonable. It notes too that Mr. Luth proposes that the increase in the S.C. No. 1N in customer charge be offset by a decrease in the distribution charge. And, he further proposes that Peoples Gas' S.C. No. 1H charge be set no higher than the Peoples Gas proposed $19.00 charge. According to the Utility, Mr. Luth makes no additional specific recommendations concerning Peoples Gas' S.C. No. 1H distribution charges other than to say that they should not be reduced as long as overall cost are not recovered by rates. Further, Mr. Luth does not propose any changes to North Shore's S.C. No. 1N.

The Utilities maintain that they have presented proposals for S.C. No. 1N and S.C. No. 1H rates that are comprehensive, detailed, and analytical. On the other hand, they argue, the rate proposals of Mr. Glahn are very general and not based on any cost studies or reasoned analysis.

In the Utilities view, Mr. Luth proposes very reasonable customer charges for Peoples and North Shore S.C. Nos. 1N and 1H. He also reasonably recommends that Peoples Gas' S.C. No. 1N distribution charges be reduced to offset the increase in the customer charge but makes no recommendation as to distribution rates for the Utilities' S.C. No. 1N.

According to the Utility, Mr. Luth proposes to reduce the distribution rates for North Shore's S.C. No. 1H as his ECOSS allocates fewer costs to S.C. No. 1H than North Shore's ECOSS. This would also be reasonable, the Utility asserts. But the Utility considers his proposal for Peoples Gas S.C. No. 1H distribution charge as being too general to warrant any consideration. Where the customer charge proposals of the Utilities do not differ significantly from Staff witness Luth's proposals, they maintain that the approval of the Utilities' comprehensive and well reasoned proposals for rates for S.C. No. 1N and S.C. No. 1H would amount to acceptance of a large part of the Staff proposal.

(2) Staff

Staff observes Peoples Gas to propose to bifurcate the present residential service classification ("SC") 1 into SC 1N and SC 1H. The distinction, Staff notes, is based upon the use of natural gas at the residential customer's service address. More specifically, the distinction is based upon for what use the natural gas is being used for, i.e., heat or non-heat. As such, Staff observes, SC 1N would apply to residential customers who do not use natural gas for space heating purposes, while SC 1H would apply to residential customers who use natural gas for space heating purposes. The Utility-proposed rates under SC 1N would offer an $11.25 per month customer charge that is lower than the $19.00 per month customer charge under SC 1H, but a 49.77¢ per therm single, or flat-block usage charge, that is higher than the declining two-block usage charges of 35.220¢ and 10.768¢ per therm under SC 1H.

Staff does not necessarily oppose the separation of residential customers according to usage. But, it contends that the separation should be based upon volume, i.e., low usage vs. higher usage. In many, if not most cases, Staff believes that its proposed separation would have the same end result as the Utilities' proposal, based upon how natural gas is used (i.e. Heat or Non Heat) because space heating typically requires far more natural gas than non-space heating uses. In Staff's view, if a non-space heat customer uses sufficient volumes of natural gas such that a billing under SC 1N would exceed a billing under SC 1H, the non-space heat customer should not be forced to pay more than a SC 1H customer with comparable usage simply because the non-space heat customer does not use natural gas for space heating. If anything, Staff notes, the relatively high-use non-space heating customer should pay less than the heating customer for the same usage because the load profile for the non-heating customer should be expected to be more constant, thereby minimizing the need for extra capacity costs for service during demand peaks. Staff Ex. 19.0 at 9.

Staff's solution to non-space heating customers possibly qualifying for SC 1H rates is for the customer to be given a choice whether to be billed during the off-peak, summer months under SC 1N or SC 1H. Id. at 9-11. In Staff's view, customers should be advised of the opportunity to change how they will be billed for the next 12 months, and further advised that the choice will remain in effect until the following June 15th. According to Staff, the Utility would provide generic information to the customer to consider in making the choice between SC 1N and SC 1H, such as the break-even point for monthly usage where SC 1N billing becomes more expensive than SC 1H billing, and leave for the customer to consider how natural gas will be used over the next October 15th through June 15th period.

If the administrative challenge of providing residential customers a choice between SC 1N and SC 1H billing is overly burdensome to the Company, then Staff proposes that the cost of service and billing unit information for the proposed SC 1N and SC 1H customer classes should be combined to develop a set of rates for an SC 1 customer class. Currently, Staff notes, residential non-space heating and space heating customers are subject to the same rates for the same usage, so combining the two types of customers would not represent a change in how those customers are billed. At the Company-proposed revenue requirement, the lower customer charges with UBA suggested by Company witness Grace are acceptable to Staff if the proposal to separate SC 1N and SC 1H customers with UBA is rejected by the Commission. NS-PGL Ex. VG-3.0 at 12, table preceding line 247. Staff does not support Rider UBA, but it is not reasonable that a customer charge without Rider UBA would be higher than if Rider UBA is authorized by the Commission. The proposed Rider UBA is a per-therm charge, Staff explains, so the lack of Rider UBA should affect usage charges, but not the customer charge.

If the Commission approves the separation of residential customers into SC 1N and SC 1H, Staff recommends that rates be based upon its cost of service study. Staff proposed rates, it explains, would result in a subsidy from SC 2 customers of approximately $9.94 million, meaning that SC 1N and SC 1H customers would pay a combined $9.94 million less than cost of service at the Utility-proposed revenue requirement. Under Utility-proposed rates, Staff notes that SC 1N and SC 1H customers would pay $20.1 million less than cost of service at the Utility-proposed revenue requirement, and this would require a larger amount above cost of service from SC 2 customers. Staff is sensitive not only to rate increases affecting customers, but also to the amount customers pay relative to cost of service. Thus, in Staff's view, since SC 2 is being asked to pay for SC 1N and SC 1H costs in addition to SC 2 costs, SC 2 revenues above SC 2 costs should be minimized despite SC 1N and SC 1H revenues that would average approximately 44¢ per therm for delivery.

Staff notes CUB-City and the AG to object to the customer charges that Staff witness Luth proposed, which are based upon the Staff cost of service study results, the revenue requirements proposed by Peoples Gas and North Shore, and a customer charge that is lower than SC 1N and SC 1H customer costs. Staff Ex. 19.0, Sched. 19.2-NS, S.C. 1 Non-heating and S.C. 1 Heating col., *Amount (under) class cost of services*, Customer Charge Revenues line; and Sched. 19.2-PG, S.C. 1 Non-heating and S.C. 1 Heating col., *Amount (under) class cost of service*, Customer Charge Revenues line. Staff observes both CUB-City of Chicago and the AG to believe that the customer charges recommended by Mr. Luth are too high and should be lowered, consistent with the position outlined by their joint witness Glahn. Had Mr. Luth been a strict constructionist with a singular focus on recovering a class's cost of service, as the AG argues, Staff points out that the customer charge would have been more than what he proposed because SC 1N and SC 1H customer costs are not fully recovered through the proposed customer charges and distribution charges. Increased customer charges would have required SC 1N and SC 1H customers to pay more than proposed by Staff, even at the lower SC 1N and 1H cost of service Staff proposed compared to the Companies. Furthermore, a lower customer charge relative to class cost of service would have required either: 1) a higher distribution charge in the first usage block to recover a greater level of customer costs, or 2) an increased subsidy from another customer class to pay for the under-recovered SC 1N and SC 1H costs.

Increases to other customer service classifications are also high on a percentage basis under the revenue requirement proposed by Peoples Gas, such that Staff considers requiring further increases from these customers to fund SC 1N and SC 1H costs to be unreasonable. Staff Exhibit 19.0 at 18-19. It is seems possible to Staff, that a lower revenue requirement authorized by the Commission would make some increases less difficult. Staff believes, however, that SC 1N and SC 1H should move closer to cost of service, particularly when other customer classes are also facing significant rate increases. Id. at 19-20.

Staff contends that the Utilities are mistaken in claiming that Mr. Luth makes no recommendation on SC 1N distribution rates. NS-PGL Init. Br. at 169. Staff points out that Mr. Luth presented SC 1N distribution rates in his rebuttal testimony. Staff Ex.

19.0, Sched. 19.1-NS, p. 1 of 8, col. [F], lines 2-5 and 18-21; p. 4 of 8, lines 2-8 and 22-28; and Sched. 19.1-PG, p. 1 of 11, col. [F], lines 2-5 and 18-21; p. 5 of 11, col. [F], lines 2-5 and 22-28. These rates, Staff explains, are based upon the results of Staff's cost of study at revenue requirements proposed by North Shore andPeoples Gas, with a subsidy from SC 2 to SC 1N and SC 1H and having the effect of reducing SC 1N and SC 1H rates. Staff Ex. 19.0 at 18-20.

(3) City-CUB

i. Bifurcation of Peoples Gas S.C. No. 1

City-CUB maintain that the Utilities have not shown that there to be a significant difference in the cost of serving Peoples Gas S.C. 1 heating and non-heating customers or that bifurcation would reduce or eliminate any subsidy flowing between heating and non-heating customers. Thus, they argue, S.C. 1 should remain as a single class.

City-CUB note the Utilities to contend that, based on the ECOSS, there is a "significant difference in fixed costs" for heating and non-heating customers. Id*.* at 11. The testimony of GCI witness Glahn, however, observes that the ECOSS appears to assign an implausibly high portion of costs to heating customers relative to the costs assigned to non-heating customers. *See* GCI Ex. 3.0 REV. at 16. City-CUB explain that Mr. Glahn used a Peoples Gas work paper to calculate the average cost per customer of meters, regulators and services for Peoples Gas S.C. 1H and 1N customers, and he noted that the per-unit cost of regulators for non-heating customers is less than a third of the cost for heating customers, and that the per-unit cost of services for non-heating customers is approximately one-third the cost for heating customers. Id. at 16-17. He further explained that the allocation of service plant seems particularly implausible because the cost of installing services presumably would depend largely on labor and construction costs that "should vary little by the size of the pipe, at the sizes typically used for residential customers." Id*.* at 17. Additionally, City-CUB observe Mr. Glahn to have questioned whether the utility would dig up an old service and replace it with a larger one every time a non-heating customer decides to install a gas furnace and become a heating customer, or instead simply install from the beginning services that would accommodate a range of end uses. Id*.* at 7-11. In any event, City-CUB argue, the Utilities have not convincingly explained why there is such an apparently large disparity in the cost of services for heating and non-heating customers in S.C. 1.

In the City-CUB's view, the Companies' attempt to account for these differences adds more confusion rather than clarification. Mr. Amen's testimony, they note, discusses purported cost of service differences relating to whether the service being installed is used by a single customer or is shared by multiple customers. Specifically, Mr. Amend responded to Mr. Glahn, by stating that:

> Mr. Glahn's average per customer calculations for service plant fail to account for the occurrence of multiple S.C. No. 1 non-heating customers served by shared gas lines. This is the predominant characteristic for non-heating residential customers on Peoples Gas' system and not an uncommon industry practice where there are separately metered multi-

> family dwelling units served by a single service line and apartment units for other natural gas end uses. In fact, 97% of Peoples Gas' non-heating residential customers share a gas service line while almost half (47%) of the residential heating customers are served by a separate, dedicated service line.

NS-PGL Ex. RJA-2.0 at 15.

The City-CUB assert that the Utilities have failed to reconcile this testimony with Ms. Grace's account that, S.C. No. 1 includes only dwellings with two or fewer units. Tr. at 959 (Grace). If this is the case, Mr. Amen's explanation for the cost of service differential between S.C. 1 heating and non-heating customers is implausible. It seems highly unlikely, the City-CUB argue, that service costs vary significantly, i.e., by a 3-to-1 ratio, as calculated by Mr. Glahn, according to whether the service is used by one customer or is shared by two customers.

City-CUB note Mr. Amen to have testified that, a "relatively prevalent practice" in the gas distribution industry is to have two single-family dwellings share a single service. Tr. at 321. In such cases, he added, "the service line has enough capacity, generally speaking, that it doesn't require a larger service than it otherwise would to service a single customer," depending on the pressure system to which the service is connected. Id.

City-CUB assert that the apparent contradiction between the Utilities witness testimonies carries through to Mr. Amen's surrebuttal testimony, where he responds to Mr. Glahn's observation that the primary driver of cost of service differentials appears to be whether the customer is a residential single- or multi-family customer, or residential single- versus shared-service customers (whether the customer falls in S.C. 1 or another class), and not whether the customer is an S.C. 1 heating or non-heating customer. Specifically, Mr. Amen countered that the direct assignment of service plant to S.C. 1 heating and non-heating customers and the resulting cost differential properly reflects the design considerations of the services, which require larger services to be installed where multiple customers are connected to a single service with cumulatively larger connected peak loads as well as the length of those services. NS-PGL Ex. RJA-3.0 at 9-10.

Regardless of the precise meaning of the ambiguous term "multiple" in this testimony, City-CUB contend that it is problematic. If "multiple" means "more than two," then this is inconsistent with Ms. Grace's testimony regarding the types of customers included in S.C. 1. If "multiple" would just mean "two," Mr. Amen's testimony strains credulity and conflicts with his hearing testimony that oftentimes larger services are not required to serve two single-family dwellings. And, it is unclear to City-CUB whether Mr. Amen's observation that "[a]s a group, heating customers place a significantly higher peak load on the system than do non-heating customers" refers to all heating and non-heating customers or just heating and non-heating customers in S.C. 1. Id. at 8.

In the City-CUB's view, an approval of the bifurcation of S.C. 1 into heating and non-heating sub-classes cannot be had on the basis of a questionable cost of service differential that may, or may not apply, to heating and non-heating customers *in S.C. 1*.

The Utilities alone bear the burden of proof in this proceeding, *see* 220 ILCS 5/9-201(c), the City-CUB argue. And, in their view, the Utilities have failed to establish that the significant difference in the cost to serve S.C. 1 customers is due to a heating/non-heating distinction and not to the single/multiple family factor Mr. Glahn identified.

ii. Customer Charges for S.C. 1N and 1H

(a) Peoples Gas Proposal

Based on its proposal to bifurcate S.C. 1, City-CUB observe that Peoples Gas proposes to increase its customer charge for S.C. 1H customers from $9.00 to $19.00 per month – a 111 percent increase – and the corresponding charge for S.C. 1N customers from $9.00 to $11.25 per month. *See* PGL Ex. VG-1.4 at 2. They would have the Commission deny Peoples Gas's request in this regard based on Mr. Glahn's testimony that substantially higher customer charges for S.C. 1H customers would harm low- and fixed-income customers.

According to Ms. Grace, City-CUB note, Mr. Glahn fails to recognize that, customers' total bills do not necessarily increase if customer charges are increased because higher customer charges are offset by lower volumetric or distribution charges. NS-PGL Ex. VG-2.0 at 37. The reason that Mr. Glahn did not address total bill impacts, the City-CUB point out, is that such impacts are irrelevant to his fundamental point, i.e., low- and fixed-income customers are more adversely affected by higher fixed customer charges than higher distribution charges because the former charge, unlike the latter, cannot be managed through reducing consumption. *See* GCI Ex. 6.0 REV. at 12.

City-CUB further observe Ms. Grace to claim that, according to Peoples Gas' analysis, the average use for the "lowest income customers" is higher than the class average use per customer for S.C. No. 1H. NS-PGL Ex. VG-2.0 at 37-38. This analysis simply does not establish what she claims it does.

City-CUB note this analysis to compare the average use of households by zip code in Chicago with the various mean annual household income ranges for each zip code, the lowest range being $32,000 to $40,000. *See* NS-PGL Ex. VG 2.8-PGL. According to City-CUB, It does not reveal the average use of the lowest income customers, as Ms. Grace maintains; it shows the average use of customers residing in the zip codes with the lowest mean household income range. After all, that households in a particular neighborhood have a particular average income does not mean that the actual incomes of every – or any – household in that neighborhood is exactly the average income. Rather, as Ms. Grace admitted on cross-examination, average household income for a particular zip code suggests that the zip code includes households with incomes both higher and lower than the mean income. Tr. at 965. City-CUB observe that Peoples Gas's analysis does not identify the actual individual household incomes for a particular zip code, thus leaving unknown whether a zip code includes extreme highs or lows in household income that are not suggested by the mean household income.

Moreover, Ms. Grace's reliance on the conclusions of a witness regarding the relationship between usage and household income in another jurisdiction, Missouri, with distinct demographic, housing stock and other relevant characteristics does not cure the deficiencies in Peoples Gas's study. *See* NS-PGL Ex. VG-2.0 at 38. In fact, Peoples Gas's graph of average use for certain household income ranges, NS-PGL Ex. VG 2.8-PGL, does not remotely resemble the "U" shape relationship between usage and income described in the excerpt of the witness's testimony in the Missouri case quoted by Ms. Grace.

Assuming *arguendo* that Ms. Grace is correct about low-income customers' gas consumption levels, City-CUB maintain that this does not justify more than doubling fixed charges for S.C. 1 heating customers. Instead, the solution that both protects low-income customers, and (unlike the Companies' proposal to lower distribution charges) sends a proper price signal, is targeted energy efficiency assistance programs that provide low-income customers with weatherization and energy efficient appliance rebates to control gas usage. GCI Ex. 6.0 REV. at 13. City-CUB argue that Peoples Gas' proposal to lower distribution charges, is itself ground for rejecting its rate design proposals for S.C. 1N and 1H. Lowering volumetric charges, they assert, sends the wrong price signal, i.e., to consume more gas, and this results in violation of the AGA's "conservation of resources" rate design objective. *See* GCI Ex. 3.0 REV. at 7 & 31. Because increased consumption requires the burning of more natural gas, lowering volumetric charges also fails to meet the "environmental protection" rate design goal. *See id.*

Unable to refute these assertions, Ms. Grace attempts to minimize the anti-conservation effect of Peoples Gas's proposal to reduce volumetric charges, insisting that the gas cost portion of customers' bills sends "the appropriate signal on gas consumption." NS-PGL Ex. VG-2.0. This case, the City-CUB argue, does not concern the gas or commodity cost portion of customer bills or total bill impacts; it concerns the delivery services portion of bills, including the customer charge and the distribution charge. *See* PGL Ex. RJA-1.0 at 11. The undeniable fact is that, in proposing a fixed rate element and a consumption-related rate element for the distribution portion of the bill in this case, the Companies chose to lower the volumetric charge – the only distribution rate element that sends a price signal relating to consumption. And Ms. Grace's assertion that moving "more cost recovery to fixed charges enhances the price signal," (NS-PGL Ex. VG-2.0 at 39) – a signal that would not affect usage – fails to address the goal of encouraging conservation, a rate design objective that the Companies' proposals ignore. Accordingly, the Companies' proposed customer charges for S.C. 1N and 1H should be rejected.

In lieu of Peoples Gas' unreasonably high proposed customer charges for S.C. 1 heating and non-heating customers, the Commission should adopt Mr. Glahn's recommended S.C. 1 customer charges. Consistent with his recommendation to keep S.C. 1 whole, Mr. Glahn proposes setting the monthly customer charge for Peoples Gas S.C. 1 at no more than $10.50 – a 16.7 percent increase above the current level. If approved, Mr. Glahn's proposed customer charge for Peoples Gas S.C. 1 would require that the distribution charge for that class be adjusted to meet the revenue requirement for Peoples Gas adopted by the Commission. Id. at 32. Mr. Glahn's proposed increase in customer charges would increase Peoples Gas's recovery of fixed costs through fixed charges, but without placing an undue hardship on smaller customers, including in particular low- and fixed-income customers. *See* GCI Ex. 3.0 REV. at 31-32.

As shown in GCI Ex. WLG -3.1, Sched. 6, City-CUB assert that Mr. Glahn's proposed customer charges would be comparable to the customer charges for similar rate classes of other Illinois investor-owned natural gas utilities. This favorable comparison does not establish, as Ms. Grace would have it, that Mr. Glahn "arbitrarily set" his proposed customer charge based on the customer charges of other Illinois utilities. To the contrary, Mr. Glahn's Direct Testimony made clear that Mr. Glahn developed his proposed customer charge for S.C. 1 to achieve rate design objectives such as social goals and stability that Peoples Gas's proposals utterly fail to meet. That Mr. Glahn's proposed charges – unlike Peoples Gas's – are comparable to those of other LDCs regulated by the Commission merely indicates that they share a rate design philosophy the Commission has accepted as reasonable for such fixed charges. *See* GCI Ex. 3.0 REV. at 27-33. Nor is there merit to Ms. Grace's claim that Mr. Glahn's proposed Peoples Gas S.C. 1 customer charge is not "cost based," (NS-PGL VG-2.0 at 35) Mr. Glahn recommends increasing the customer charge to increase recovery of fixed costs, just not at the pace proposed by Peoples Gas, a pace that would unduly burden small residential customers. Thus, Mr. Glahn's proposal is properly based on cost as well as other established rate design criteria.

(b) Staff Proposal

City-CUB urge the Commission to not adopt Staff witness Luth's proposed customer charges for S.C. Nos. 1N and 1H because, in their view, these fail the same rate design criteria as the Utility's proposal. For Peoples Gas, they note, Mr. Luth would increase the customer charge for S.C. 1N customers from $9.00 per month to $12.00 per month, a 33.3 percent increase that is even higher than Peoples Gas's proposed $11.25 monthly charge, and increase the S.C. 1H customer charge to $19.00 per month, just as the Utility has proposed. Staff Ex. 7.0 at 25-26. Like Peoples Gas's proposal, City-CUB assert, Staff's recommendations are narrowly focused on moving rates closer to full cost recovery and fail to take account of the impact of substantially increasing customer charges on small residential ratepayers, and particularly, low- and fixed-income customers. GCI Ex. 6.0 REV. at 16-17.

iii. North Shore

For the reasons discussed in section IX.C.2.a. above with respect to Peoples Gas S.C. 1, the Companies' proposal to bifurcate North Shore S.C. 1 into heating and non-heating sub-classes should also be rejected.

With respect to customer charges, City-CUB note that North Shore proposes increasing its monthly customer charge for S.C. 1H from $8.50 to $16.00 per month (an 88 percent increase) and to increase the corresponding charge for S.C. 1N customers from $8.50 to $10.50 per month. NS Ex. VG-1.4 at 2. For the same reasons that City-

CUB dispute proposed increases in Peoples Gas's customer charges, they maintain that proposed customer charges for North Shore should be rejected. In this instance too, City-CUB argue, the Commission should adopt Mr. Glahn's recommendation to keep North Shore S.C. 1 whole, and to maintain the existing $8.50 monthly customer charge for that class. This recommendation, they assert, is based on the position of GCI witness David Effron that North Shore's overall revenue requirement should be reduced. Keeping the North Shore S.C. 1 customer charge at the current level while reducing total revenues for the utility, they argue, would increase the proportion of fixed costs recovered through fixed charges, consistent with the Utilities' stated goal in this case. GCI Ex. 3.0 REV. at 34; *see also* NS Ex. VG-1.0 REV. at 7.

(4) AG

The AG maintains that the Utilities' proposal, to bifurcate the residential Rate 1 class, produces a significantly higher customer charge proposal for Peoples and North Shore heating customers, as compared with their Non-heating Rate 1 customers. And, the AG observes, their proposed residential rate design also includes *lower* per therm distribution charges.

GCI witness Glahn noted that while the customer charge for Peoples is increasing at a triple digit rate, the volumetric charges are falling by more than 8 percent for volumes over 50 therms. PGL Ex. VG-1.4. Similarly, with respect to North Shore, while the customer charge is increasing by 88 percent, the volumetric charges are falling by a significant 45 percent for volumes over 50 therms. NS Ex. VG-1.3.

When reviewing these proposed rates, Mr. Glahn the Commission should keep a number of points in mind. First, any increase in a rate element of more than 100 percent constitutes rate shock and, consequently, fails all tests for "gradualism," notwithstanding Utilities' witness Grace's assurances to the contrary. GCI Ex. 3.0 at 30. Second, the Companies are proposing no mitigation measures, such as a multi-year phase-in. Id.

The AG observes Mr. Glahn to have testified that sharply higher fixed costs "fall disproportionately on those least able to pay," thereby failing the "social goals" test. Id. Moreover, he indicated that a proposal that would have some elements increase dramatically, while other rate elements fall dramatically, fails the "stability" test. Id. at 31. In addition, having volumetric rate elements decrease sends the wrong price signal, given the Companies' claims that overall costs for Peoples and North Shore have increased by more than $100 million and more than $6 million, respectively. Id. In addition, lowering distribution charges discourages conservation efforts, failing the "conservation of resources" test, another rate design objective referenced by Mr. Glahn. Id. Lowering volume charges fails the "environmental protection test" as well, given the fact that the actual burning of natural gas produces negative environmental impacts. Id.

The AG maintains that the concept of "social goals" in rate design is important when considering residential customers. Mr. Glahn noted that low income and fixed income customers fall disproportionately into the Heating subcategory. Id. at 19-21. Thus, the AG contends, the proposed $19 fixed customer charge imposes a significant burden upon low-income households in the Chicago area, and represents more than four percent of their monthly income. Id. at 14. And, unlike distribution charges, the AG points out, customer charges cannot be mitigated by reducing usage. According to the American Gas Association, "(s)ocial ratemaking goals involve rate designs that advance the welfare of a particular group in society." Id. at 21. For persons on fixed incomes, "higher utility prices may mean a significant decrease in well-being," according to the AGA. Id.

Illinois' seasonal prohibition on gas company shut-offs supports Mr. Glahn's assertion that the provision of affordable utility service is an important social goal. Similarly, the aforementioned requirement in the Public Utilities Act that rates be "least-cost" confirms Mr. Glahn's position. It is noteworthy that "social goals" were not among the goals stated by Utilities' Grace in describing the Companies' rate design objectives.

Staff witness Luth, apparently a strict constructionist when it comes to following ECOSS, recommended imposing customer charges that are even higher than the Companies propose. For Peoples Gas' residential Non-heating customers, Mr. Luth recommended the customer charge increase *beyond the level proposed by the Company* from the current \$9.00 per month to \$12.00 per month, a 33 percent increase that is higher than the \$2.25 increase proposed by Peoples. ICC Ex. 7.0 at 25, 26. For Peoples' heating customers, Mr. Luth concurs with the Company's proposal to increase the customer charge by 111 percent to \$19.00. Id.

For North Shore, Mr. Luth endorsed the customer charge proposals proposed by the Company for both Heating and Non-heating customers. Id. at 20. Mr. Luth's rationale for supporting (and increasing) the customer charges proposed by the Companies amounts to a concern that "customer costs are under-recovered by the proposed customer charges." Id. at 25. Despite his acknowledgement during cross-examination that gradualism is one of the goals of rate design, Tr. at 1464, 1465, nowhere are the rate design concepts of gradualism or social goals mentioned within his singular focus on recovering a class's cost of service. In fact, he recognized that "a \$10 increase might impact some people hard, yes." Tr. at 1469.

As the Commission ponders the cost allocation and rate design dilemma, along with the competing views as to whether and to what degree residential customer charges need to be increased, it is helpful to re-examine Bonbright's views on the matter. What is clear is that the residential customer charges proposed by the Companies are excessive, and not aligned with legitimate principles of rate design.

In order to correct the inequities and satisfy the aforementioned rate design goals, Mr. Glahn proposed that the monthly customer charge for all Peoples Gas customers be set at no more than \$10.50. Id. The \$10.50 amount represents a \$1.50 or 16.7 percent increase over the current level. Id. In conjunction with that rate, he proposed that the volumetric charge would then be adjusted to achieve the needed revenue requirement, based on the level of revenue increase ultimately awarded to Peoples Gas. Id. at 32. Mr. Glahn clarified that his proposal would maintain the current distribution charge design. This includes retaining the current two-block rate design distribution charge for non-heating customers. Id.

For North Shore's residential customers, Mr. Glahn recommended that the monthly customer charge for both heating and non-heating customers be retained at the current $8.50 level, based on GCI witness Effron's conclusion that the Company's overall revenues should be reduced. Id. at 34. He noted that keeping this rate element the same, while reducing overall revenues, increases the amount of fixed costs collected through fixed charges. Id. Mr. Glahn's recommended customer charges, after adjusting the corresponding volumetric charges appropriately, would allow both Companies to fully recover their revenue requirements. Id. at 10.

As a point of comparison, the AG notes, Mr. Glahn examined the customer charges for similar rate classes found at Illinois' other investor-owned natural gas utilities. His Exhibit WLG 3.1, Schedule 6, attached to GCI Exhibit 3.0, contains a comparison between the fixed monthly charges and volumetric charges for residential and small commercial customers for these various utilities. Mr. Glahn's proposed Peoples Gas customer charge falls in the middle of the charges listed, and would exceed the level charged by Illinois Power Company and Nicor Gas Company. Id. at 33.

The Companies' proposal to increase Peoples Gas Rate 1 Heating customer charges for Peoples Gas and North Shore customers by 111% and 88% should cause the Commission to keep a number of points in mind. First, any increase in a rate element of more than 100 percent constitutes rate shock and, consequently, fails all tests for "gradualism," notwithstanding the Companies' assurances to the contrary. GCI Ex. 3.0 at 30. Second, the Companies are proposing no mitigation measures, but rather suggest that these proposals satisfy notions of gradualism and rate design continuity. PGL-NS Brief at 163, 167. This assertion simply cannot be taken seriously.

The AG urge the Commission to look beyond claims of a need for strict, fixed cost recovery when designing rates, especially since the record shows that the Companies *have* recovered their fixed costs in the past when rates supposedly recovered only 30% of fixed costs through fixed charges. PGL-NS Brief at 163. The Companies proposed customer charges are excessive, and not aligned with legitimate principles of rate design.

In order to correct the inequities and satisfy the aforementioned rate design goals, Mr. Glahn proposed that the monthly customer charge for all Peoples Gas customers be set at no more than $10.50. Id. The $10.50 amount represents a $1.50 or 16.7 percent increase over the current level. Id. In conjunction with that rate, he proposed that the volumetric charge would then be adjusted to achieve the needed revenue requirement, based on the level of revenue increase ultimately awarded to Peoples Gas. Id. at 32. Mr. Glahn clarified that his proposal would maintain the current distribution charge design. This includes retaining the current two-block rate design distribution charge for non-heating customers. Id.

For North Shore's residential customers, Mr. Glahn recommended that the monthly customer charge for both heating and non-heating customers be retained at the current $8.50 level, based on GCI witness Effron's conclusion that the Company's overall revenues should be reduced. Id. at 34. He noted that keeping this rate element the same, while reducing overall revenues, increases the amount of fixed costs

collected through fixed charges. Id. Mr. Glahn's recommended customer charges, after adjusting the corresponding volumetric charges appropriately, would allow both Companies to fully recover their revenue requirements. Id. at 10.

As a point of comparison, Mr. Glahn examined the customer charges for similar rate classes found at Illinois' other investor-owned natural gas utilities. His Exhibit WLG 3.1, Schedule 6, is attached to this Brief as Appendix B, and contains a comparison between the fixed monthly charges and volumetric charges for residential and small commercial customers for these various utilities. Mr. Glahn's proposed Peoples Gas customer charge falls in the middle of the charges listed, and would exceed the level charged by Illinois Power Company and Nicor Gas Company. Id. at 33.

Mr. Glahn's common-sense approach to designing rates is superior to the Companies' proposals, which are guided solely by their continuing quest to ensure margin revenue and fixed cost recovery. A customer charge of no more than $10.50 satisfies the goal of gradualism, while still contributing to increasing the portion of fixed costs recovered in the customer charge. Moreover, it satisfies the social goals that have guided this Commission's rate-setting practices in the past, which includes some subsidization for the residential class and avoidance of rate shock. Finally, increasing the distribution charges sends customers the correct price signals, which include a recognition that increased usage can result in the need for system expansions and defeat the goal of conserving resources. Id. Mr. Glahn's proposed rate design for the residential class should be adopted.

(5) Utilities Response

The Utilities note the GCI parties to argue that the bifurcation has not been justified and should be rejected, while Staff urges that if the bifurcation is approved, a procedure is needed permitting customers to annually elect the classification under which to receive service. For their part, the Utilities' bifurcation proposal is based upon the significant cost differential between small residential heating (S.C. No. 1H) and non-heating (S.C.No.1N) customer classifications and the appropriate designation of accounts based upon utility information, practices and analyses. NS-PGL Init. Br. at 165-169.

According to the Utilities, Staff does not oppose bifurcation *per se*, but would base it upon volume, i.e., high usage versus low usage, instead of their heating versus non-heating distinction. And, Staff would apply its annual customer election features in either case.

The Utilities further observe Staff to indicate that, if its proposed annual customer election feature is considered to be administratively challenging or burdensome, the Utilities should consider developing rates for a non-bifurcated service classification which would collapse proposed S.C. No. 1N and 1H into a single S.C. No. 1. Staff also indicates that it would find acceptable a customer charge developed by Ms. Grace at the Utility's proposed revenue requirement with Rider UBA if the Commission does not approve Rider UBA. *See* Staff Init. Br. at 236. As such, Staff implicitly agrees with the Utilities' approach to developing a S.C. No. 1 customer charge if the Utility's bifurcation proposal is not approved. Staff, however, proposes that a lower customer charge be based on a revenue requirement with Rider UBA, even if Rider UBA is not approved. According to the Utilities, it would be more logical and more consistent that the Commission accept a customer charge that is aligned with the approved revenue requirement. Thus, the Utilities outline, the customer charge should be based on the revenue requirement without Rider UBA (if Rider UBA is not approved), and with Rider UBA (if Rider UBA is approved). If the Commission is put to choose between the Utilities' bifurcation proposals and Mr. Luth's "customer election" proposals, which would adversely impact the Utilities as well as customers, the Utilities would prefer a customer charge using its proposed approach. *See,* NS-PGL Ex. VG-3.0 at 16.

The Utilities maintain their position that their proposed bifurcation for S.C. No. 1H and S.C. No. 1N is justifiable and should be approved and not complicated by the Staff's convoluted and overwhelmingly problematic annual election proposal. No such enhancement is necessary, they claim, because it would impose a level of complexity and confusion into the process that is not warranted. The Utilities contend to have demonstrated and, it is unrebutted, they argue, that reliable and fairly comprehensive data exists to justify bifurcation along heating and non-heating lines. The Utilities further assert that they conducted a cost study analysis which demonstrates that heating customers create significantly higher system costs than non-heating customers. While Mr. Luth made a vague reference to a volume based bifurcation model, the Utilities maintain that he offered no reasoning or data to support why volume should be the basis for bifurcation.

In opposition to the Utilities' bifurcation proposal, they observe the AG to make a series of unconnected and partially applicable claims. For example, the AG asserts that an increase of 100% "in a rate element" - - i.e., in any <u>part</u> of a bill such as a single charge -- constitutes rate shock. AG Init. Br. at 137. The Utilities contend that the AG's argument is exaggerated given that it only focuses on the Utilities' proposed customer charges for S.C. No. 1H and completely ignores the offsetting decreases in the proposed distribution charges.

According to the Utilities, the AG attempts to couch its criticism in theoretical constructs. As such, AG urges that the Utilities' increases "fall disproportionately on those least able to pay", thereby failing a purported, "social goals test". <u>Id</u>. It is basic, the Utilities point out, that any rate increase of any kind will affect those with less ability to pay but, they argue, the AG has made absolutely no showing to support its claim of "disproportionality." Further, the Utilities note that following the AG's line of reasoning, any rate increase would fail its "social goals test", i.e., a test which has no legal force but is merely one principle, among many, some contradictory and inconsistent, which are posited by a theoretician, Dr. Bonbright. On the other hand, Peoples Gas maintains that it has proven that low-income customers tend to consume gas at levels higher than the class average and that its proposed rate design would be more favorable to such customers than the lower customer charge, higher distribution charge rate design that would arise from Mr. Glahn's proposal. Similarly, North Shore's rate design would be favorable for low-income customers during the winter period when gas prices are typically higher. *See* NS-PGL Ex. VG-2.0 at 37-39 & 43.

While the Utilities observe the AG to refer to a "conservation of resources" test and an "environmental test" with the claim that these also fail because lowering distribution charges discourages conservation and causes negative environmental impacts. AG Init. Br. at 137-138. The Utilities maintain however, that gas costs, which are the most significant portion of a customer's bill, provide the appropriate test. *See* NS-PGL Ex. VG-2.0 at 29. According to the Utilities, the AG's reference to theories and purported tests is highly selective and would create the impression that its favored goals are paramount in rate design. In their view, a reasonable rate design must incorporate goals that are considerably more even handed and broadly applicable.

To this end, the Utilities assert that the testimony of Ms. Grace points out that the they have proposed rates and rated designs that incorporate many of the theoretical principles, including social goals, that typically apply in rate design. She also notes that there is no requirement that rate designs must meet all theoretical rate design objectives or that such a feat is even possible. Even Mr. Glahn acknowledges that there are often conflicts among rate design objectives. The Utilities have sought to employ sound rate design principles and other measures that they believe are most appropriate and reflect their interests of all customers and customer groups. As such, they argue, the Commission must disregard false and irresponsible assertions such as the suggestion that the Utilities have "fudged their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any other costs categories." AG Init. Br. at 149. No such allegation or implication can be found on the record or otherwise regarding the Utilities' rate design proposals.

The Utilities consider the AG's intent is to preserve an unwarranted rate design advantage for residential customers to be well apparent from Mr. Glahn's proposal to set the monthly customer charges for Peoples Gas at $10.50 and $8.50 for North Shore. Mr. Glahn proposes these customer charges in an almost casual manner. He offers absolutely no cost analysis or justification to support them, aside from broad references to customer charges of other Illinois utilities, never analyzing or explaining how their costs structures require that their resulting rates should in any way apply to the Utilities. In short, Mr. Glahn's customer charge proposals are superficial, not well reasoned and completely unsupported by any cost or rate analysis. They appear to be purely outcome driven. This Commission, the Utilities argue, should not endorse such a careless and parochial approach to designing customer charges and the proposals of the AG must be denied.

City-CUB engages in similar end-results oriented pleading to advocate unreasonably low customer charges. City-CUB makes several of the same claims as AG that despite all clear reasoning to the contrary, lower customer charges must be preserved to protect the interests of one group of customers – low and fixed income rate payers. In the final analysis, the Utilities argue, City-CUB has offered no more persuasive reasoning in support of Mr. Glahn's proposals.

The Utilities contend that they have each presented proposals for S.C. No. 1N and S.C. No. 1H rates that are comprehensive, detailed and analytical. In contrast, they argue, the rate proposals of Mr. Glahn are very general and not based on any cost studies or reasoned analysis.

The Utilities further observe that Mr. Luth proposes very reasonable customer charges for Peoples and North Shore S.C. Nos. 1N and 1H. And, he also reasonably recommends that Peoples Gas' S.C. No. 1N distribution charges be reduced to offset the increase in the customer charge. He makes no recommendation as to distribution rates for North Shore and Peoples Gas' S.C. No. 1N. Mr. Luth proposes to reduce the distribution rates for North Shore's S.C. No. 1H as his ECOSS allocates fewer costs to S.C. No. 1H than North Shore's ECOSS. This would also be reasonable. However, his proposal for Peoples Gas S.C. No. 1H distribution charge is too general to warrant any consideration. Where the customer charge proposals of the Utilities do not differ significantly from Staff witness Luth's proposals, the Utilities contend that approval of their comprehensive and well reasoned proposals for rates for S.C. No. 1N and S.C. No. 1H would amount to acceptance of a large part of the Staff proposal.

(6) Commission Analysis and Conclusion

The issue is whether to implement a bifurcation between S.C. Nos. 1N and 1H as the Utilities have here proposed. Having reviewed the evidence, the Commission concludes that bifurcation of S.C. No. 1 into two service classifications would be reasonable, but it has concerns about both the Utilities' and the Staff's proposals. Staff witness Luth has included proposals for implementing an election procedure and he would differentiate the proposed S.C. No. 1H and S.C. No. 1N customers based on small volume vs. larger volume instead of the Utilities' heating vs. non-heating distinction. These are each interesting proposals in their own way. In the end, however, the Commission believes that Mr. Luth's proposal to establish bifurcation along volumetric lines is somewhat vague and insufficiently detailed to permit full consideration. And, his customer election proposal brings up unnecessary problems. The Commission agrees with the Utilities that the introduction of annual elections for service classifications would result in unwarranted complexity and it would bring about customer confusion. Further, the Commission is unable to ascertain precisely what benefits would be obtained by customers switching service classifications without a reasonable and appropriate reason for doing so. At the same time, however, Mr. Luth has raised valid concerns about the impact of the Utilities' proposal on those non-heating customers who may have relatively high usage in a given month. While there appear to be a small number of customers falling into this category, the Commission agrees with Mr. Luth that they should not pay a higher rate than if they were on S.C. No. 1H. Accordingly, the Commission does not adopt the Utilities' proposed bifurcation. In its place, the Utilities have proposed a rate design to retain a single service classification for small residential customers. The Commission finds this proposal, including the method for setting the customer and distribution charges, to be a reasonable alternative to bifurcation of S.C. No. 1.

The Commission also concludes that the embedded cost of service study is the most appropriate means of assigning costs to S.C. Nos. 1N and 1H and the application of the EPEC method, in conjunction with the cost study, generates rates that properly reflect a greater recovery of fixed costs as the Commission believes is appropriate. In considering Mr. Glahn's approach, we find it inconsistent and outside the goals of increasing fixed cost recovery. As we see it, Mr. Glahn's proposal would generate rates using the filed revenue requirement that are substantially below those proposed by the Utilities. It is difficult to evaluate in full the propriety of Mr. Glahn's proposal because it is unaccompanied by sufficient analysis or justification in the form of a cost study or some other measure. While the Commission is sensitive of the need to balance social goals with other objectives in its rate design determination, we do not believe the parties opposing the Utilities' proposal have demonstrated that the Utilities have employed anything less than the settled broad objectives of rate design, including social goals, in the S.C. No. 1N and S.C. No. 1H proposals at hand.

In the final analysis and with these same considerations in mind, the Commission believes that the Utilities' proposed alternative to bifurcation represents the most reasoned approach to establishing just and reasonable rates for small residential heating and non-heating customers. Specifically, the Commission rejects proposals to bifurcate S.C. No. 1 and adopts: the Utilities' alternative proposal to retain a single service classification for small residential customers; the Utilities' proposed customer charges for both Utilities' S.C. No.1 classification to be set at 50% of the revenue requirement for S.C. No. 1; the Utilities' proposals for calculating the distribution rates, including a declining two block rate; Peoples Gas' use of the EPEC method; establishing North Shore's S.C. No. 1 distribution rate using the methodology described in NS-PG Ex. VG-3.0 at pages 20-21.

c) Peoples Gas Service Classification No. 2

d) North Shore Service Classification No. 2

These issues have been merged.

(1) Utilities

Peoples Gas proposes to increase the monthly customer charge for S.C. No. 2 customers and to move the charges for meter classes one and two closer to embedded cost for each individual meter class, instead of considering an average of the embedded customer cost for all S.C. No. 2 customers. Under its proposal, monthly customer charges would increase from $15.00 to $21.00 for Meter Class 1 and increase from $22.00 to $60.00 for Meter Class 2. These charges, Peoples Gas maintains, are supported by the ECOSS. Peoples Gas is also proposing to maintain the three declining block distribution charge for SC No. 2 and to allocate 23%, 61% and 16% of the remaining customer, demand and commodity costs to the front, middle and end blocks, respectively.

According to Peoples Gas, the front block charge has been increased to 35.441 cents, the middle charge has been increased to 13.669 cents per therm and the end block has been decreased to 7.199 cent per therm. The proposed S.C. No. 2 charges exclude the gas cost portion of uncollectible expenses, which would be recovered through Rider UBA. Without Rider UBA, the proposed customer charges would remain the same but the front, middle and end block charges would be 37.695 cents per therm, 14.5339 cents per therm and 7.655 cents per therm, respectively. PGL Ex. VG-1.0 REV at 22-23.

Mr. Glahn proposes to increase Peoples Gas' Meter Class 1 customer charge to $27.00 so that it "matches" a charge for one utility and "falls in the midst" of certain other utilities. On the other hand, Peoples Gas notes that Mr. Glahn selectively avoids any comparison for Meter Class 2 as Peoples Gas' proposed rate at $60.00 is less than the $70.00 and $90.00 rates charged by those certain other utilities. According to Peoples Gas, Mr. Glahn's proposals are based on arbitrary, inapt comparisons and not on sound ratemaking principles.

North Shore proposes to increase the monthly customer charge for S.C. No. 2 customers and move the charges for Meter Classes 1 and 2 closer to the embedded cost for each individual meter class, instead of considering an average of the embedded customer cost for all S.C. No. 2 customers. The proposed monthly customer charges would increase from $15.00 to $17.00 for Meter Class 1 and from $22.00 to $60.00 for Meter Class 2. The proposed customer charges are less than the embedded fixed cost for each meter type and are supported by the ECOSS. North Shore is proposing to also maintain the three declining block S.C. No. 2 distribution charge and allocate 25%, 55% and 20% of the remaining customer demand and commodity cost to the front, middle and end blocks respectively. The front block increases to 23.248 cents per therm, the middle block decreases to 8.716 cents per therm and the end block decreases to 2.769 cents per therm. The proposed S.C. No. 2 rates for North Shore do not include the gas cost portion of uncollectible expense which is recovered through Rider UBA. Without Rider UBA the monthly customer for North Shore would mostly remain the same and the front, middle, and end block charges would be 24.175 cents per therm, 9.064 cents per therm, and 2.879 cents per therm, respectively. NS Ex. VG-1.0 3REV at 19-20.

The Utility notes Mr. Glahn to propose that the North Shore S.C. No. 2 customer charges not be increased. In its view, however, he offers no reasoned analysis or other detail to support his proposal. Thus, the Utility argues, Mr. Glahn's S.C. No. 2 recommendations are arbitrary and without merit.

Although Peoples Gas does not agree with Mr. Luth's undefined rate increase methodology for S.C. No. 2, it notes that his rate design proposals are consistent with those proposed by Peoples Gas. As to North Shore's S.C. No. 2, however, there appears to be some divergence of opinion between Mr. Luth and North Shore.

Mr. Luth proposes to change North Shore's S.C. No. 2 demand device and transportation administrative charges. Those charges, are cost based and rider specific for North Shore's proposed transportation Riders AGG, SST and P, irrespective of a customer's service classification. According to the Utilities, it is not appropriate to adjust rider specific charges simply to meet a particular service classification's revenue requirement. If North Shore's S.C. No. 2 needs to be adjusted to meet its revenue requirement, the Utilities consider that it would be more appropriate to adjust charges that are applicable to the service classification, rather than a charge designated in several riders that applies to several service classifications. NS-PGL Ex. VG-3.0 REV at 23.

(2) City-CUB

City-CUB observe Peoples Gas to propose increasing the monthly customer charge for its S.C. No. 2 Meter Class 1 from $15.00 to $21.00 or a 40 percent increase. For its S.C. No. 2 Meter Class 2, they point out that the Utility seeks an increase from $22.00 to $60.00 – a 173 percent increase. *See* PGL Ex. VG-1.4, p. 2. As Mr. Glahn noted, however, any increase in a rate element of more than 100 percent "constitutes rate shock, and thus fails all tests for 'gradualism,' despite assurances from Ms. Grace to the contrary." GCI Ex. 3.0 REV. at 30. To avoid imposing rate shock on S.C. 2 customers – particularly Meter Class 2 customers – and to meet the rate design objective of gradualism, Mr. Glahn recommends limiting the new customer charge for Meter Class 1 to no more than $19.00 – 26.6 percent above the current level. Id*.* at 32. This charge, the City-CUB contend, would match the comparable customer charge for MidAmerican and "fall in the midst of the other comparable [Illinois] utilities' rates." Id*.* at 34. For Meter Class 2, Mr. Glahn recommends limiting the new customer charge to $27.00 or 22.7 percent over the current charge. This proposed charge is higher than that of MidAmerican and somewhat below the comparable charges of some Illinois utilities with two-tiered rates, but it is appropriate given Peoples Gas's declining block structure for volumetric charges. Id*.* at 34; *see also* GCI Ex. 3.1, Sched. 6. Assuming Mr. Glahn's recommendations were approved, City-CUB note that the corresponding volumetric charges would need to be adjusted to achieve Peoples Gas's approved revenue requirement. Id*.* at 32.

According to City-CUB, Mr. Glahn's comparison of his proposed customer charges to those of comparable Illinois utilities is not the only bases for his proposal. NS-PGL Ex. VG-2.0 at 44. Mr. Glahn's recommended customer charges for S.C. 2 are designed to avoid rate shock and to comport with gradualism, *see* id*.* at 29-34; and that the resulting charges also happen to fall within the range of such charges imposed by other Illinois utilities merely demonstrates that they fall within a reasonable range. NS-PGL Ex. VG-2.0 at 44.

City-CUB observe that North Shore proposes increasing the monthly customer charge for its S.C. No. 2 Meter Class 1 from $15.00 to $17.00. And, North Shore seeks to increase the customer charge for Meter Class 2 from $22.00 to $60.00 or a 173 percent increase. *See* NS Ex. VG-1.3 at 2. Based on GCI witness Effron's recommended reduction to North Shore's revenue requirement, and to avoid imposing rate shock on S.C. 2 customers, Mr. Glahn recommends retaining the respective $15.00 and $22.00 charges for Meter Classes 1 and 2. Keeping this rate element the same while reducing the utility's overall revenues would increase the proportion of fixed costs recovered through fixed charges – one of the Companies' stated goals in this proceeding. *See* NS Ex. VG-1.0 REV. at 7.

(3) AG

The AG charts the Utilities proposed customer charges for Rate 2 General Service and notes that the Companies' proposal would increase the Rate 2, Meter Class 2 customer charges by 173 percent. According to the AG, this amounts to rate shock and violates any notion of gradualism. For his part, Mr. Glahn proposed that any approved increase in the Companies' revenue requirement should be allocated by increasing the customer charge for Meter Class 1 General Service customers to no more than $19.00, an increase of $4.00 or 26.6 percent from current levels. GCI Ex. 3.0 at 32. For meter class 2, Mr. Glahn recommended limiting the customer charge increase to $5.00, which would produce a $27 monthly charge, or a 22.7 percent increase from the current level. Id. Like his recommendations for residential distribution charges, the volumetric charge would then be adjusted to achieve the needed revenue requirement, based on the level of revenue increase or decrease ultimately awarded to the Companies. Id.

The AG asserts that Mr. Glahn's proposed Rate 2 customer charges satisfy the goal of gradualism, while still contributing to increasing the portion of fixed costs recovered in the customer charge. These should be adopted by the Commission.

The AG notes the Companies to criticize these proposals as arbitrary because Mr. Glahn observed that they "fall in the midst" of certain other utilities' Rate 2 customer charges. Indeed, comparison of other utilities' rates was considered legitimate, as discussed below, for the Companies' proposed Dishonored Check fee. Mr. Glahn's proposal should be adopted by the Commission.

(4) Commission Analysis and Conclusion

The Commission considers the Company's proposal to be the most reasonable means to design the S.C. No. 2 rates. Mr. Glahn's proposal lacks sufficient analysis. If not arbitrary, in making other utility comparisons for meter class 1, it is at times inconsistent, by not applying this approach to meter class 2. While gradualism is certainly a goal, it may overshadowed by other equally important considerations. We seriously question why Mr. Glahn proposes to limit the increase to the S.C. No. 2 customer charges to such a degree that they would remain far below the fixed costs for this service classification. Mr. Luth's proposal to change the S.C. No. 2 demand device and administrative charges is not defended on Reply Brief and does not appear to be based on any cost basis or other persuasive reasoning. On the whole, the increases proposed by the Utilities are shown to be warranted. While Mr. Luth's proposal to change the S.C. No. 2 demand device and administrative charges would result in proper cost recovery, we decline to adopt his proposal at this time because the demand device and administrative charges apply to other service classifications a well as S.C. No. 2. On the whole, the increases proposed by the Utilities are shown to be necessary. The exceptions of City-CUB and the AG do not persuade us otherwise.

e) North Shore Service Classification No. 3

(1) Utilities

North Shore's current S.C. No. 3 is a cost based rate that serves large volume, high load factor customers. The Utility inform us that present rates include a monthly two block demand structure which is set at 5,000 therms and over 5,000 therms. North Shore proposes to increase the front block to 10,000 therms to better reflect the higher monthly demand volumes that are representative of this service classification. The minimum, average and maximum monthly demand volumes for this service classification are 19,000 therms, 26,000 therms and 34,000 therms, respectively.

The current demand block structure, which current data show is set too low, results in 19% of demand volumes falling within the first block and 81% of demand volumes falling in the end block. This does not allow North Shore to recover its demand costs through a reasonable rate design that accurately reflects the customer profile. To remedy this, at least partially, and to allow a more balanced cost recovery, the Company proposes to increase the front block to 10,000 therms. This would result in 38% of demand volumes falling within the first block and 62% of demand volumes falling within the second block. The revenue from S.C. No. 3 will be set at embedded cost as determined in the ECOSS. This is consistent with the rate treatment in North Shore's last rate case. NS Ex. VG-1.0 3REV at 21-22.

The demand charge will be set at 80% of cost, with 50% being recovered through the front demand block. That results in about 75% of the total S.C. No. 3 revenue requirement being recovered through the demand charges. The front block (0-10,000 therms) demand charge will be set at 49.065 cents per demand therm and the end block (over 10,000 therms) demand charge will be set at 30.574 cents per demand therm. The monthly customer charge will be set at cost and will be $705.00. The monthly standby service charge will be set at 11 cents per therm of standby demand with the remaining revenue being recovered through the distribution charge, which will be set at .262 cents per therm. Id. at 22.

Staff witness Luth proposes to allocate $236,527 more costs to S.C. No. 3 based on his use of the Average and Peak methodology over the amount that North Shore proposed. While he does not propose any changes to the customer charge, he is proposing to recover 23.1% of the S.C. No. 3 demand costs through the distribution charge resulting in an increase in the proposed S.C. No. 3 distribution charge to 0.46 cents per therm. Applying this proposed rate to the S.C. No. 3 distribution volumes results in distribution charge revenue of $85,246, which is only $36,693 higher than what North Shore proposed. A comparison of this amount to Mr. Luth's additional $236,527 of proposed S.C. No. 3 costs, results in an under-recovery of S.C. No. 3 costs of approximately $199,800.

According to North Shore, Mr. Luth failed to account for these additional costs in his revenue adjustments for S.C. No. 3. In addition, North Shore proposed to recover only 80% of demand related costs in the demand charge, with the remaining demand and commodity costs being recovered through the standby service charge and the distribution charge. This proposal is very similar to what Mr. Luth is proposing, but Mr. Luth used a different cost allocation methodology. As Mr. Luth agrees with North Shore's proposed customer charge and derives a demand charge which is similar to that proposed by North Shore, the distribution charge would need to be adjusted to appropriately recover the revenue requirement arising from his ECOSS. The charges would also need to be adjusted to reflect revenues arising from the standby service charge that was corrected. NS-PGL Ex. VG-2.10. Based on that correction, the standby service charge would be reduced from 11 cents per therm to 7 cents per therm.

Even with the proposed changes, all charges would need to be supported by the final ECOSS arising from this proceeding. NS-PGL Ex. VG-2.0 at 46-47.

Mr. Luth does not address North Shore's S.C. No. 3 in his Rebuttal Testimony although Staff Ex. 19.0, Schedule 19.1-NS accompanying that testimony reflects different demand and distribution charges than those proposed in his Direct Testimony and in data responses. Otherwise, Mr. Luth's customer charge proposal approximates that proposed by North Shore. NS-PGL Ex. VG-3.0 REV at 26. Given the lack of clarity attending Mr. Luth's proposals for North Shore's S.C. No. 3 charges, the Commission should adopt the Company's proposal which appears not to differ greatly from Mr. Luth's recommendations

(2) Commission Analysis and Conclusion

The Commission accepts the Company's S.C. No. 3 proposal. Staff noted, in its brief on exceptions, that the rates it developed for SC 3 were not sufficiently different from rates that would result from the Company's rates to warrant an objection.

f) Peoples Gas Service Classification No. 4

(1) Utilities

The Company's current S.C. No. 3 is a cost based rate that was designed to serve large volume, low load factor customers. The Company's current S.C. No. 4 is a cost based rate that was designed to serve large volume, high load factor customers. In the Company's last rate case the average load factors for S.C. No. 3 and S.C. No. 4 were 42% and 75%, respectively. Currently, these load factors are 37% and 51%, respectively. As the difference in average load factors has significantly narrowed between the two service classifications, Peoples Gas maintains that it is no longer necessary to provide service under two separate large volume service classifications. Combining these two service classifications under S.C. No. 4, Large Volume Demand Service, is also supported by the Company's ECOSS which demonstrates that on a per demand therm basis, there is very little difference in costs.

The revenue from S.C. No. 4 will be set at embedded cost for S.C. Nos. 3 and 4 combined as determined in the ECOSS. This is consistent with the rate treatment in the Company's last rate case. The monthly customer charge will be set at cost and will be $565.00. The demand charge will be set at 80% of cost, with 70% being recovered through the front demand block. That results in about 59% of the total S.C. No. 4 revenue requirement being recovered through the demand charges. The monthly standby service charge will be set at 24 cents per therm of standby demand with the remaining revenue being recovered through the distribution charge, which will be set at 1.211 cents per therm. The front block (0-7,500 therms) demand charge is 50.609 cents per demand therm and the end block (over 7,500 therms) demand charge is 40.163 cents per demand therm.

Currently, S.C. No. 3 customers are not required to have a daily demand measurement device to determine billing demand although S.C. No. 4 customers are required to have such a device. As the Company is proposing to increase the amount of the revenue requirement being recovered through the demand charge, these customers will be required to have a daily demand device to determine billing demand. This should have a minimal impact on most S.C. No. 3 customers as about 90% of the current customers already have such devices installed. For those customers who do not have a daily demand device installed, until such device can be installed, the billing demand will be calculated using the same methodology currently used to make such a determination for transportation customers.

The sales customers' standby demand will be the same as their billing demand and the Rider SST customers' standby demand will be their selected standby demand. The Company would propose the same charges as those with Rider UBA. PGL Ex. VG-1.0 REV at 24-26.

Using his ECOSS, the Utilities note that Mr. Luth's proposal would results in only 33% of demand costs being recovered through the demand charge. This shifts 60% of demand cost recovery through a volumetric distribution charge with 7% of demand costs being recovered through the standby service charge. Mr. Luth's ECOSS shows volumetric commodity costs for Peoples Gas' S.C. No. 4 of $804,826 while his proposal results in recovery of $9.1 million or 1,119% over the amount that should be recovered on a volumetric basis. Mr. Luth expresses concern about Peoples Gas' increased demand charge for former S.C. No. 3 customers but overlooks the impact that his higher distribution charge would have on all customers. Mr. Luth's proposal would more than triple the distribution charge for current Peoples Gas' S.C. No. 4 customers. Mr. Luth's proposed rate designs, which are not based on sound ratemaking principals, would be uneconomical to customers in this service classification and may induce some to switch to S.C. No. 2 or bypass Peoples Gas' system. Conversely, Peoples Gas' proposals are reasonable and based on sound ratemaking principals.

(2) City-CUB

City-CUB maintain that tor the reasons they discussed in section IX.B.1., above, Allocation of Rate Increase, the rates for Peoples Gas S.C. 4 should be adjusted to move the class from 96 to 116 percent of the class's cost of service. And, rates for Peoples Gas S.C. 3, which the Companies propose to combine with People Gas S.C. 4, should be set at 107 percent of cost. *See* GCI Ex. 3.1, Sch. 2.

(3) Commission Analysis and Conclusion

The Commission accepts the Company's proposal to combine Rate 3 and 4, noting that we have not been presented with any persuasive evidence why the two service classifications should remain separate in view of the convergence of load factors that has been demonstrated. Staff in its exceptions indicated that at this stage of the proceeding it was no longer contesting this issue. Further, City-CUB have not set out an effective or meaningful analysis for their proposals.

g) Peoples Gas Service Classification No. 7

(1) Peoples Gas

Peoples Gas' current S.C. No. 7, Contract Service, is available to any customer for whom bypass of the Company's gas distribution system is economically feasible and practical. PGL Ex. VG-1.0REV at 27. The Company proposes to change the description of this services classification from “Contract Service” to “Contract Service to Prevent Bypass” to make it more descriptive and allow for a longer term contract in response to customer requests. Id. at 27. No parties have contested those issues.

Peoples Gas considers Mr. Glahn’s proposal to allocate costs to S.C. No. 7 to be flawed. First, the Company observes that it is rooted in his belief that Peoples Gas “assumes that the costs to service this group of customers has not increased since 1995.” GCI Ex. 3.0 REV at 13. Peoples Gas explains that its present tariff limits contract terms for customers served under this service classification to five years. As a result, it contends, contracts which may have been in place since Peoples Gas’ last rate case over eleven years ago have been renegotiated based on the proper cost considerations. And, Peoples Gas’ allocation has been performed against the backdrop of the circumstances presently in place in respect of the contracts, i.e., data which has changed since 1996. Furthermore, Mr. Glahn never explained how any rate increase he might impute into rate design could be factored into the binding contracts that are currently in effect and that may expire up to five years from the effective date of Peoples Gas’ increase. Accordingly, the Company urges that Mr. Glahn’s proposed allocations for S.C. No. 7 be rejected by the Commission and Peoples Gas’ proposed changes be approved.

(2) Staff

Staff considers the issue to be uncontested between Staff and the Company. According to Staff, the Company proposed to change the title of this service from “Contract Service” to “Contract Service to Prevent Bypass” to be more descriptive. The Company also proposed to allow a contract to extend longer than the current maximum of five years, i.e., a maximum of up to ten years. Also, the Companies proposed minor editorial changes. PGL Ex. VG-1.0 2REV at 27. Staff witness Harden found all of the Company’s proposed changes to be acceptable. As set out in her testimony: (1) the changes are very minor with the exception of the change from a 5-year contract to a 10-year contract, (2) the increase in the length of the contracts would allow any costs that might be associated with the contracts to be spread out over a longer period of time and (3) a longer contract also saves the cost of the time it takes to negotiate a new contract between the parties. Staff Ex. 9.0 at 6.

(3) AG

On reply, the AG responds to the criticism of Mr. Glahn’s proposal to allocate costs to S.C. No.7, the service classification formerly known as Contract Service, and the argument that he does not explain “how any rate increase he might impute into rate design could be factored into the binding contracts that are currently in effect” and may expire after the effective date of the Peoples Gas rate increase. PGL-NS Init. Br. at 176.

According to the AG, the Companies’ argument ignores the fact that Mr. Glahn is not suggesting that Peoples has to charge S.C.7 a certain rate based on the allocation. Whether the Companies elect to recover these additional costs from S.C.7 customers is up to the Companies. GCI Ex. 6.0 at 9. The AG’s concern is that, despite being grouped with S.C.6 and 8, S.C. 7 is allocated none of the increase because, according to Ms. Grace, the revenues from S.C.7 are based on negotiated, contract rates. Id. at 13 (*citing* PGL Ex. VG-1.0 at 8). Mr. Glahn correctly noted that regardless of how prices are determined for members of S.C. 7, there is a cost to serve these customers. These customers use the same system facilities and services as all of the other S.C. customers. Id. at 8. Peoples provided no evidence that there is no cost to serve these customers. Some of the increases in costs that the Company alleges has occurred should be imputed to S.C. 7 customers. Such imputation corresponds with the other allocations to customer classes proposed by Mr. Glahn. As such, his recommendation in this regard should be adopted.

(4) City-CUB

City-CUB maintain that for the reasons discussed in section IX.B.1. above, 26.6 percent (the average system increase) of Peoples Gas's proposed rate increase should be apportioned to Peoples Gas S.C. 7. *See* GCI Ex. 3.1, Sch. 2.

(5) Commission Analysis and Conclusion

The Commission recognizes that S.C. No. 7 is a classification under which all rates are contractually based and individually negotiated. This service classification has been renamed, with the approval of Staff, to clarify that it is intended to address bypass concerns. We see no reason to effectively penalize the Company by attributing costs to the service which the utility might not be able to recover. As such, the Commission finds Mr. Glahn's proposal to be unwarranted under the whole of the circumstances. The exceptions of City-CUB and the AG restate earlier arguments and are not persuasive.

D. Tariffs – Other Tariff Issues

The Utilities have proposed certain changes in a variety of tariffs and for various reasons. None of the intervening parties have opposed any of the changes to the Tariff issues set out in this section, with the exception of the AG, and City-CUB, who oppose the $25.00 NSF charge. Staff, however, has objected to the language in some of these Tariffs. All but two of the objections have been resolved.

1. Rider 2, Factor TS

a) Utilities

The Utilities propose to revise Rider 2 to reflect the applicability and the renaming of applicable transportation riders. They also propose to eliminate Factor TS, Transition Surcharge and refund or recover any dollars awaiting recovery or refund through Factor NCGC, Non-Commodity Gas Charge. Staff witnesses Kahle and Harden support the Utilities proposal to roll Factor TS balances into their non-commodity gas charges. Staff Ex. 9.0 at 24; Staff Ex. No. 21.0 at 2-3. Given that no other parties have addressed this matter, the Utilities maintain that this proposal is uncontested.

b) Staff

Staff recognizes that the Companies have proposed changes to Rider 2 to reflect the applicability of the rider based on their proposal to eliminate and rename applicable transportation riders. NS Ex. VG-1.0 3REV at 31 and PGL Ex. VG-1.0 2REV at 35. The proposed changes that refer to other riders are appropriate in Staff's view, if the Commission approves the elimination and renaming of certain transportation riders. Staff Ex. No. 9.0 at 25.

The Companies' propose to eliminate Factor TS – Transition Surcharge, and refund or recover any dollars awaiting recovery or refund through Factor NCGC – Non-Commodity Gas Charge. NS Ex. VG-1.0 3REV at 31; PGL Ex. VG-1.0 2REV at 35. Staff recommends the Commission approve the Companies' proposed elimination of Factor TS language in Rider 2 if the Commission approves Staff's recommendation to roll Factor TS balances into their non-commodity gas charges. Staff Ex. 21.0 at 10.

According to Staff, Rider 2 also reflects minor editorial changes to clarify language and pursuant to the Commission's Order in Docket 06-0540, and reflects the change to a calendar year for its fiscal year. NS Ex. VG-1.0 3REV at 31–32 and PGL Ex. VG-1.0 2REV at 35-36. Staff points out that, In Docket 06-0540, the Companies requested approval to change reconciliation years in the Gas Companies' Riders 2 and 11 to calendar year bases. And, the Commission approved the request at page 64 of its Final Order in that docket. Staff Ex. 9.0 at 24.

c) Commission Analysis and Conclusion

The Commission accepts the Utilities' proposal to revise Rider 2 to reflect the applicability and renaming of applicable transportation riders. Also, we accept the proposal to eliminate Factors TS, Transition Surcharge, and refund or recover any dollars awaiting recovery or refund through NCGC, Non-Commodity Gas Charge.

2. Charge for Dishonored Checks and/or Incomplete Electronic Withdrawal

a) The Utilities

The Utilities propose to increase their charge for dishonored checks and incomplete electronic withdrawals from $10.00 to $25.00 to better reflect prevailing rates for such checks and transactions and to discourage customers from making deficient payments to the Company. PGL Ex. VG-1.0 REV at 32. They note that the Commission has approved an increased charge of $25.00 for Mid American Energy in Docket No. 99-0534. And, the Utilities observe the Mid American Order to state that the increase "would serve to discourage payment with checks that are not valid" and "that revenues from this charge will serve to reduce the rates of those customers who make valid payments." Re MidAmerican Energy Company, 2000 WL 3444650, Docket No. 99-0534, Order (July 11, 2000).

In these proceedings, as in MidAmerican Energy, the Utilities contend that revenue from the Utilities' charge will offset the increase in base rates in this proceeding. PGL Ex. VG-1.0 at 32. They further point out that Staff witness Harden is supportive of the Utilities' proposal. Staff Ex. 9.0 at 11. Only GCI witness Glahn opposes the increase in the charge for dishonored checks and incomplete electronic withdrawals, basing his opposition on a lack of a cost study. GCI Ex. 6.0 REV at 15; GCI Ex. 3.0 REV at 35. The Utilities consider that this Commission was clear when it approved a similar increase in the MidAmerican Energy Order to better reflect prevailing rates and to discourage customers from making deficient payments to the company. As Staff agrees, the Commission should approve the increase for dishonored checks and incomplete electronic withdrawals.

b) Staff

Staff agrees with the Utilities that the proposed increase in revenues from this fee will offset the increase in base rates in this proceeding and that MidAmerican Energy has raised the same fee to $25 as well, based on the Commission's approval in Docket 99-0534. Staff Ex. 9.0 at 10-11. Staff witness Harden further agreed with the Commission's position in the MidAmerican Energy case, i.e., that the increase in the fee would discourage customers from writing bad checks. Id. at 11.

c) The AG

The AG notes the Companies to rely on the charge authorized in the MidAmerican Energy case as support for the fee increase. PGL-NS Init. Br. at 178. Moreover, the Companies maintain that the new fee would serve to discourage payment with checks that are not valid. Id. at 177 (*citing* PGL Ex. VG-1.0 at 32; NS Ex. VG-1.0 at 28, 29). The Companies also assert that the increased charge will "offset the increase in base rates in this proceeding." Id. at 178.

GCI witness Glahn testified that this significant increase in fees is without cost support, which serves as a useful starting point and is an indispensable reasonableness check on rates. GCI Ex. 3.0 at 35. In response to an AG data request seeking support for the proposed fee, the Companies indicated that they performed no analyses, research or other studies with respect to the $25 fee. *See* GCI Ex. 3.1, Schedule 7. Accordingly, Mr. Glahn recommended that the Commission retain these charges at current levels until they provide a reasonable cost basis to support them. Id.

Addressing Mr. Glahn's challenges, the AG observes Utilities witness Grace to have stated that the Companies' proposed $25 fees "reflect the prevailing rates for such checks and transactions" and "the need to deter such payments." PGL-NS Ex. VG-2.0 at 52-53. And, the Company referenced a similar charge in the MidAmerican Energy case as further support for the fee increase. Id. According to the AG, however, the Companies data request response detailed in Schedule 7 of Mr. Glahn's direct testimony reveals that typical returned check fees "fall well below the $25 level proposed by the Companies and, in some instances, well below the $10 fee currently charged. Id. at 15 (*citing* GCI Ex. 3.1, Schedule 7).

In the AG's view, the record evidence does not support the Companies request to increase this fee by more than 66 percent. The Commission should retain the Companies $10 fee for dishonored checks, as recommended by Mr. Glahn.

d) City-CUB

The Companies propose to increase the charge for dishonored checks and/or incomplete electronic withdrawal from $10.00 to $25.00. PGL Ex. VG-1.0 REV. at 32-33; NS Ex. VG-1.0 REV. at 28-29. Because the Companies have failed to provide a cost basis for their proposal, it should be rejected.

According to the Companies, the proposed $25.00 charge reflects "the prevailing rates for such checks and transactions" and would "discourage customers from making deficient payments to the Companies." Id. Conspicuously absent from this assertion is any reference to the actual costs the utilities incur in dealing with dishonored checks or incomplete electronic withdrawals. *See* City-CUB Init. Br. at 121; GCI Ex. 3.1, Sched. 7. Instead, the Companies' proposal appears to be based on the eight-year-old MidAmerican Energy case and Staff witness Harden's Direct Testimony in this case, which cites the MidAmerican Energy case as the sole basis for her endorsement of the utilities' proposal. *See* Staff Ex. 9.0 at 11; *see also* Staff Init. Br. at 241. Because there is no cost basis in this record to support the proposed $25 charge, the charge for dishonored checks and incomplete withdrawals should be maintained at its current level. *See* City-CUB Init. Br. at 121.

e) Commission Analysis and Conclusion

The Commission finds the arguments of GCI witness Glahn unpersuasive. As pointed out by both the Utilities and Staff, this Commission has previously approved an increased charge of $25.00 in MidAmerican Energy. Id. at 716-17. Our rationale in MidAmerican Energy set out that, the increase "would serve to discourage payment with checks that are not valid" and "that revenues from this charge will serve to reduce the rates of those customers who make valid payments." The Commission is not made aware of any good reason to abandon, in this instance, the logic that drove our result in the MidAmerican Energy case. Nothing set out in City-CUB's exceptions is persuasive on the issue.

3. Rider 4, Extension of Mains

a) The Utilities

The Utilities propose changes to Rider 4 to clarify language and to address certain practices and customer preferences. The basic structure of Rider 4 is unchanged. The Companies are responsible for the costs associated with certain main installations as Part 500 of Commission's Rules provides. In those instances where, for example, a customer requests that the Companies install a main in a different location than is required to provide service, the customer would bear the incremental costs associated with meeting the customer's preferences. PGL, Ex. VG-1.0 REV at 36. Staff witness Harden disagreed with the language of Rider 4 regarding "return" and testified that the proposed language should not be approved for Rider 4. Staff Ex. 21.0 at 4-5. The Utilities maintain that they have conceded to the objection of Staff witness Harden and agree to remove the proposed language regarding "return." NS-PGL Ex. VG-3.0 REV at 29. No other parties addressed this matter and therefore, this matter is not contested.

b) Staff

Staff informs that under the Utilities proposal, the basic structure of Rider 4 is unchanged as it delineates the Companies and customer responsibilities. While certain language changes being proposed were acceptable to Staff, other changes caused its witness Harden some concern.

Staff witness Harden found the proposed language to be very broad and that it refers to charging customers, with no limit, for labor costs, material costs, transportation costs, overheads and return. Staff requested additional support and/or explanation for proposed language changes to Rider 4. Staff Ex. 9.0 at 26-27. Staff was not satisfied by the additional information in the Companies' rebuttal testimony (NS-PGL Ex. VG-2.0 at 53) and Staff continued to object to the proposed language of a "return" being charged to customers through Rider 4. Staff Ex. 21.0 at 5. In surrebuttal testimony, however, the Companies agreed to remove the "return" language from the Rider. NS-PGL Ex. VG-3.0 at 29. With the removal of "return" from the proposed language Staff states that its prior concerns are now satisfactorily addressed.

c) Commission Analysis and Conclusion

The Commission accepts the Utilities' proposed changes to Rider 4 as modified to address Staff's concern, i.e., removal of the language regarding "return." In all other respects the matter is uncontested.

4. Rider 5, Gas Service Pipe

a) Utilities

The Utilities propose to revise Rider 5 to clarify language and to address certain practices and customer preferences. The Utilities propose to reduce the free main extension shown in Rider 5 from 100 feet to 60 feet consistent with an agreement between Staff and parties related to questions raised by the Commission when it initiated Docket No. 03-0767. PGL Ex. VG-1.0 REV at 36. As with Rider 4, Staff witness Harden disagreed with the language of Rider 5 regarding "return" and, on this basis, recommended the language not be approved by the Commission. Staff Ex. 21.0 at 6. As with Rider 4, the Utilities agreed to concede to the objection of Staff witness Harden and remove the proposed language regarding "return". NS-PGL Ex. VG-3.0 REV at 29. No other parties addressed this matter and therefore, it is not contested.

b) Staff

Staff tells us that, in their surrebuttal testimony, the Companies agreed to remove the "return" language from the Rider. NS-PGL Ex. VG-3.0 at 29. With the removal of "return" from the proposed language, Staff's prior concerns in the matter were satisfactorily addressed.

c) Commission Analysis and Conclusion

The Commission accepts the Utilities' proposed changes to Rider 5 as modified to address Staff's concern, which removes the language regarding "return."

5. Rider 8, Heating Value of Gas Supplied

a) Utilities

The Companies propose to revise Rider 8 to reflect the applicability of the rider based on the elimination and renaming of transportation riders and to make a minor grammatical change. The revisions also specify that the Utilities will make filings only when the heating value factor changes, rather than file every month. PGL Ex. VG-1.0 REV at 37. Staff witness Harden opposes the Utilities' change regarding monthly filing requirement believing there would be no assurance that the Utilities are reviewing heating value factors. Staff Ex. 21.0 at 8. The Utilities contend that they review heating values on an ongoing basis in the due course of their business, not simply on a monthly basis. They explain that the heating value factor often remains the same for two or more consecutive months, and a filing is only needed when the factor changes. PGL Ex. VG-1.0 REV at 37. The Utilities believe it appropriate that filings be made only when there is such a change.

b) Staff

Staff notes that the Companies proposed changes to Rider 8 to reflect the applicability of the rider based on their proposal to eliminate and rename applicable transportation riders. NS Ex. VG-1.0 3REV at 33 and PGL Ex. VG-1.0 2REV at 37. The proposed changes that refer to other riders are appropriate, Staff asserts, if the Commission approves the elimination and renaming of certain transportation riders. Staff Ex. No. 9.0 at 30.

In its testimony, Staff discussed the proposed revision by the Companies to make filings regarding the heating value factor only when the heating value factor changes, rather than every month, which is the existing practice. Staff Ex. 21.0 at 6-8. The heating value factor is discussed in Administrative Code Section 500.280(a)(1) Heating Value and Calorimeter Equipment which, in part, states:

> Each utility furnishing natural gas, liquified petroleum gas or a mixture of such gases with manufactured gas shall maintain in each community or territory served by it a monthly average standard of heating value of gas authorized by the Commission for that utility and community. Such standard of heating value shall be maintained with as little deviation as practicable, and the average total heating value on any one day shall not exceed or fall blow the authorized monthly standard by more than five percent.

Staff explains that the Companies currently file an information sheet and calculation sheet(s) showing any Btu adjustment that may be necessary each month. This monthly filing, Staff contends, gives assurance to the Commission that the heating value factor numbers have been reviewed by the Companies each month and that the standard heating value, as discussed above, is being maintained. Staff notes that the Companies' proposed tariff language change is a simple wording change from "each" month to "a" month, but Staff does not recommend that it be approved by the Commission. Similarly, Staff does not recommend approval of the proposed addition of the phrase "*and remain in effect until superseded by a subsequent filing pursuant to this rider*."

The basis for Staff's position is that if a filing is only required when there is a change in the heating value, this will not provide assurance to the Commission that heating value factors are being reviewed each month. If several months go by and no filing is made, Staff contends that the Commission has less assurance that the Companies are reviewing heating value factors; whereas if a filing is made each month, then the Commission receives assurance that the heating value factors have, in fact, been reviewed by the Companies. Staff Ex. 21.0 at 6-8. Noting that the Companies did not respond to Staff's concerns in their surrebuttal testimony, Staff is unsure as to whether this is a contested issue.

c) Commission Analysis and Conclusion

We agree with the concern expressed by Staff Witness Harden regarding the need for assurance that the Utilities are reviewing heating value factors on an ongoing basis. The Utilities have shown no reason why the practice of monthly filings should not continue. We adopt Staff's recommendations in this instance.

6. Elimination of Riders 12, 13, 14, 15, CCA, and LCP

a) Utilities

Staff witness Harden agrees with the Utilities' proposed elimination of Riders 13, 14, 15, CCA, and LCP. Staff Ex. No. 9.0 at 18-21. No other parties addressed these matters, which leaves them uncontested.

b) Staff

The Companies proposed to eliminate People Gas' Rider 13 – Remote Meter Reading Devices; North Shore Rider 14 and Peoples Gas' Rider 15 – Taxes on Use of Compressed Natural Gas; Peoples Gas' Rider LCP – Low Income Customer Assistance Program; and both Companies proposed to eliminate Rider CCA – Customer Charge Adjustments. Staff agreed with the proposed eliminations of Riders 13, 14, 15, CCA and LCP. The tariff language from North Shore Rider 14, Peoples Gas Rider 15 and Rider CCA has been combined into Rider 1. Peoples Gas Rider 13 and Rider LCP are proposed to be completely eliminated. Staff Ex. 9.0 at 16-22.

c) Commission Analysis and Conclusion

We observe Staff to agree with the Utilities regarding their proposed elimination of Riders 13, 14, CCA and LCP. As such, the Commission finds the elimination of the Riders 13, 14, 15, CCA and LCP to be supported by the evidence in the record.

7. Miscellaneous Changes to Riders 1, 3, 10, and 11

a) Utilities

The Utilities point out that Staff witness Harden is in agreement with the changes to Riders 1, 3, 10 and 11, and no other parties addressed these matters.

b) Staff

Staff explains that the Companies proposed miscellaneous changes to Rider 1 – Additional Charges for State and Municipal Utility Taxes, Rider 3 – Budget Plan of Payment, Rider 10 – Controlled Attachment Plan and Rider 11 – Adjustment for Incremental Costs of Environmental Activities.

According to Staff, the changes include changing the title of the rider, adding language from proposed elimination of other riders, a change in the calendar year, converting language to a number formula and changes for consistency with other tariffs or practices and to make the language more understandable. Staff recommends approval of the changes to Rider 1, 3, 10 and 11. Staff Ex. 9.0 at 22-32.

The Companies also proposed changes to Rider 9 to reflect the applicability of the rider based on their proposal to eliminate and rename applicable transportation riders. NS Ex. VG-1.0 3REV at 34 and PGL Ex. VG-1.0 2REV at 37. In Staff's view, the proposed changes that refer to other riders are appropriate if the Commission approves the elimination and renaming of certain transportation riders. Staff Ex. 9.0 at 31.

c) Commission Analysis and Conclusion

Staff and the Utilities agree to the proposed changes to Riders 1, 3, 10 and 11. No other party has voiced an objection. Thus, these changes, as detailed below, are authorized by the Commission.

Rider 1, Additional Charges for Taxes and Customer Charge Adjustments

Peoples Gas proposes to revise Rider 1 to clarify language and to incorporate the language from Riders 15 and CCA, which are being eliminated. Rider 15 provides for taxes on the use of compressed natural gas while Rider CCA provides for charges arising from the Energy Assistance Act of 1989 and the Renewable Energy, Energy Efficiency and Coal Resources Development Law of 1997. PGL Ex. VG-1.0 REV at 35. Staff witness Harden concurs with the Companies' modifications. Staff Ex. 9.0 at 23. Staff agrees with Peoples Gas' proposal to revise Rider 1 to clarify language and to incorporate the language from Riders 15 and CCA which are being eliminated. The Commission finds the changes to Rider 1 to be supported by the evidence in the record.

Rider 3, Budget Plan of Payment

The Companies propose to revise the language of Rider 3 to make it more consistent with the Companies' current budget plan. PGL Ex. VG-1.0 REV at 36; NS Ex. VG-1.0 3REV at 32. Staff witness Ms. Harden finds the changes acceptable. Staff Ex. No. 9.0 at 26.

Staff agrees with the Companies proposal to revise the language of Rider 3 to make it more consistent to the Companies current budget plan. The Commission finds the changes to Rider 3 to be supported by the evidence in the record.

Rider 10, Controlled Attachment Plan

The Companies propose to revise Rider 10 to reflect the applicability of the rider based on the elimination and renaming of transportation riders and to make the language more understandable. PGL Ex. VG-1.0 REV at 34, 38. Staff agrees with the proposed changes in Rider 10. Staff Ex. 9.0 at 31-32. Staff agrees with the Companies proposal to revise Rider 10 to reflect the applicability of the rider based on the elimination and renaming of transportation riders. The Commission finds the changes to Rider 10 to be supported by the evidence in the record.

Rider 11, Adjustment of Incremental Costs of Environmental Activities

The Companies made minor editorial changes and revised Rider 11, as required by the Commission's order in Docket No. 06-0540 to reflect the Companies' change to a calendar year for its fiscal year. PGL Ex. VG-1.0 REV at 34 & 38. Staff agrees with the proposed changes in Rider 11. Staff Ex. 9.0 at 32-33. The Commission acknowledges the submitted revisions to Rider 11 based on its Order in Docket No. 06-0540.

8. Terms and Conditions of Service

a) Service Activation Charges

(1) North Shore/Peoples Gas

The Utilities propose to increase the Service Activation Charge, which recovers a portion of the costs related to initiating gas service at an individual premises. PGL Ex. VG-1.0 2REV at 29; NS Ex. VG-1.0 3REV at 25. There are two types of service activations: a "successor turn-on," and a "straight turn-on." It is explained that a successor turn-on occurs when the customer moving out calls and discontinues gas service at approximately the same time as the applicant moving in calls and requests gas service. In this instance only a meter reading is required.

A straight turn-on describes the instance where there has never been gas service at the location, or when the prior customer cancelled service and the gas was actually turned off before new service was requested. In this instance, the gas has to be turned on and the appliances relit. Id.

Both North Shore and Peoples Gas performed a study on these charges, and the results are set out in NS Ex. VG-1.9 and PGL Ex. VG-1.10. Both of these studies, the Utilities maintain, show that the cost is higher than the respective Company's proposed change in this docket. Staff Ex. 9.0 at 7-8. North Shore proposes charging $18.00 for a successor turn-on, and $28.00 for a straight turn-on including the relighting of four appliances, plus $5.00 for the fifth and each additional appliance to be activated. NS Ex. VG-1.0 3REV at 26. For its part, Peoples Gas proposes charging $12.00 for a successor turn-on, $20.00 for a straight turn-on, including the relighting of four appliances, plus $5.00 for the fifth and each additional appliance to be activated. PGL Ex. VG-1.0 2REV at 30.

(2) Commission Analysis and Conclusion

At hand is the Utilities' proposal to increase the Service Activation Charge, which recovers a portion of the cost related to initiating gas service at a premises. Both North Shore and Peoples Gas performed a study on these charges. The results are reflected in NS Ex. VG-1.9 and PGL Ex. VG-1.10. Both of these studies show the cost is higher than the respective Company's proposed change in this docket. Staff Ex. 9.0 at 7-8. The Commission finds the proposals to increase the Service Activation Charge are acceptable and supported by the evidence in this proceeding. We further find that no party or Staff takes issue with this proposal.

b) Service Connection Charges

(1) North Shore/Peoples Gas

The Utilities explain that a "Service Reconnection Charge" is a charge assessed to a customer whose gas has previously been turned off for any number of reasons, such as nonpayment of bills or the customer's own request. PGL Ex. VG-1.0 2REV 30-

31; NS Ex. VG-1.03REV at 27. According to the Utilities, each customer is granted a waiver of one reconnection charge each year, except in the situation where the customer voluntarily disconnects and then requests reconnection within twelve months, or in the situation where service is disconnected at the main. Id.

As with the Service Activation Charge, the Utilities propose to restructure the Service Reconnection Charge to include a basic charge that includes the relighting of up to four appliances, and to assess a charge for the fifth and each additional appliance. The Utilities are proposing a slight increase to the charges for all three types of reconnection: (1) basic reconnections which only require a meter turn-on; (2) reconnections which require the Company to set a meter; and (3) reconnections that involve excavating at the main. Id.

More specifically, North Shore proposes charging $50.00 for a basic reconnection; $90.00 if the meter has to be reset; and $275.00 if service has to be reconnected at the main. NS Ex. VG-1.0 3REV at 27. Peoples Gas proposes charging $50.00 for a basic reconnection; $100.00 for a reconnection when the meter has to be reset; and $275.00 when service has to be reconnected at the main. PGL Ex. VG-1.0 2REV at 31.

The Companies provided the results of a study on these charges in North Shore Gas Ex. VG-1.9 and Peoples Gas Ex. VG-1.10. Both of these studies, the Utilities assert, show the actual cost to be even higher than the charge the Companies are proposing in this docket.

(2) Commission Analysis and Conclusion

The Utilities propose to increase the Service Reconnection Charge, and they explain that this is a charge assessed to a customer whose gas has previously been turned off for any number of reasons, including nonpayment of bills or at the customer's own request. PGL Ex. VG-1.0 2REV at 30-31; NS Ex. VG-1.03REV at 27. The Commission finds the proposals to increase the Service Reconnection Charge are acceptable and supported by the evidence in this proceeding.

c) Second Pulse Data Capability

(1) North Shore/Peoples Gas

Certain meters, meter correctors, and daily demand measurement devices are capable of delivering a "second pulse" signal to specialized devices that can capture and transmit metering data. Second Pulse Data Capability can provide this signal and make real-time usage readings to customers. While the Companies do not require such capability, a few large volume customers have made requests to receive the second pulse output to help manage their gas usage. PGL Ex. VG-1.0 2REV at 33; NS Ex. VG-1.0 3REV at 29. Here, the Utilities propose a charge of $14.00, set at cost, to customers who elect Second Pulse Data Capability. Id.; Id. at 30.

The Utilities point out that Staff witness Harden reviewed North Shore's and Peoples Gas' supporting documentation and she agrees to the monthly charge for Second Pulse Data Capability. Staff Ex. 9.0 at 12. The Utilities further observe that no other parties have addressed this issue.

North Shore and Peoples Gas also propose to revise the first sentence of the second paragraph of the section entitled "Second Pulse Data Capability" to state "Initial terms of the contract shall end on the first April 30 following the effective date thereof, and the contract shall automatically renew for one-year periods upon expiration of the initial term and each one-year extension." This change does not substantially affect the second pulse proposal. The Utilities explain that the change was made for consistency since many of the contracts automatically rollover on May 1. NS-PGL Ex. VG-3.0 at 29.

(2) Commission Analysis and Conclusion

We observe the Utilities to propose a charge of $14.00, set at cost, to customers who elect Second Pulse Data Capability. PGL Ex. VG-1.0 2REV at 33; NS Ex. VG-1.0 3REV at 30. We further note that Staff witness Harden has reviewed North Shore and Peoples Gas' supporting documentation and she agrees to the monthly charge for Second Pulse Data Capability. Staff Ex. 9.0 at 12. On the entirety of the record, the Commission finds the proposals regarding Second Pulse Data Capability, including the cost-based charge, acceptable and supported by the evidence in this proceeding.

X. TRANSPORTATION ISSUES

A. Overview

This Section addresses issues concerning customers who obtain gas supply from alternative providers and purchase gas transportation from the Utilities.

B. Uncontested Issues

1. Demand Diversity Factor

a) North Shore / Peoples Gas

Under its current rates Peoples Gas' demand Diversity Factor is 0.50. PGL Ex. TZ-1.0 at 21. Peoples Gas has proposed to set its Diversity Factor to 0.87. Id. at 21-22. Neither any Intervenor nor Staff has filed any evidence in opposition to this proposal. Under its current rates North Shore's demand Diversity Factor is 0.50. Id. at 20. North Shore has proposed to set its Diversity Factor to 0.75. NS Ex. TZ-1.0 at 20. Neither any Intervenor nor Staff has filed any evidence or otherwise submitted any statement in opposition to this proposal.

b) Commission Analysis and Conclusion

The Commission finds that North Shore's proposed demand Diversity Factor of 0.75 is supported by the evidence and is approved. The Commission finds that Peoples Gas' proposed demand Diversity Factor of 0.87 is supported by the evidence and is approved.

2. Daily Demand Measurement Device Charge

a) North Shore / Peoples Gas

Peoples Gas proposed to change its Daily Demand Measurement Device Charge from a range of three charges, depending on the type of meter, to a single charge of $28.00 per month. PGL Ex. TZ-1.0 at 48; PGL Ex. TZ-1.17. Neither any Intervenor nor Staff has filed any evidence in opposition to this proposal. North Shore proposed to change its Daily Demand Measurement Device Charge from a range of three charges, depending on the type of meter, to a single charge of $34.00 per month. NS Ex. TZ-1.0 at 46; NS Ex. TZ-1.17. Intervenors and Staff filed no evidence in opposition to this proposal.

b) Commission Analysis and Conclusion

The Commission finds that North Shore's Daily Demand Measurement Device Charge of $34.00 per month is supported by the evidence and is approved. The Commission finds that Peoples Gas' Daily Demand Measurement Device Charge of $28.00 per month is supported by the evidence and is approved.

3. Elimination of Rider TB (North Shore)

a) North Shore

North Shore proposed to eliminate Rider TB. NS Ex. TZ-1.0 at 17. Intervenors and Staff filed no evidence in opposition to this proposal.

b) Commission Analysis and Conclusion

The Commission finds that North Shore's proposed elimination of Rider TB is supported by the evidence and is approved.

4. Revised Calculation of Average Monthly Index Price

a) North Shore / Peoples Gas

North Shore proposed to change its calculation of the Average Monthly Index Price ("AMIP") from an average of weekly indices to an average of daily indices. NS TZ-1.0 at 45. Peoples Gas proposed to make the same change to its calculation of the AMIP. PGL TZ-1.0 at 46. Intervenors and Staff filed no evidence in opposition to this proposal.

b) Commission Analysis and Conclusion

The Commission finds that each Utility's proposed change to its calculation of AMIP is supported by the evidence and is approved.

5. Administrative Charges for Rider SST and Rider P

Peoples Gas proposed that the monthly administrative charge for Rider SST be reduced to $23.00 and that the monthly administrative charge for Rider P be set at $18.00. PGL Ex. TZ-1.6, p. 1 of 2. North Shore proposed that the monthly administrative charge for Rider SST be reduced to $21.00 and that the monthly administrative charge for Rider P be set at $13.00. NS Ex. TZ-1.6, p. 1 of 2.

Vanguard initially objected to each Utility's proposal to round the charges and complained that these rates should be set only to recover costs incurred. Vanguard Ex. 1.0 at 18; Vanguard Ex. 2.0 at 18.

In rebuttal Mr. Zack testified that the Utilities did not object to setting the Rider SST charge at $23.16 for Peoples Gas and $21.48 for North Shore and the Rider P charge at $17.55 for Peoples Gas and $12.61 for North Shore. NS-PGL Ex. TZ-2.0, at 45. No other party expressed any opposition to the revised administrative charges reflected in Mr. Zack's rebuttal testimony. Furthermore, in light of the Utilities' proposals to retain a form of Rider FST, the Utilities recalculated these monthly administrative charges, and the recalculated charges would yield a Rider SST charge of $11.24 for Peoples Gas and a Rider SST charge of $8.94 for North Shore, and a Rider P charge of $8.36 for Peoples Gas and a Rider P charge of $4.95 for North Shore. NS-PGL Ex. TZ-3.0 at 6; NS-PGL Ex. TZ-3.1.

Commission Analysis and Conclusion

The Commission finds that North Shore's proposed Rider SST charge of $8.94 and its proposed Rider P of charge $4.95 are supported by the evidence and are approved. The Commission finds thatPeoples Gas's proposed Rider SST charge of $11.24 and its proposed Rider P of charge $8.36 are supported by the evidence and are approved.

6. Elimination of 120 Day Meter Read Requirement for "Choices For You" Enrollment

a) North Shore / Peoples Gas

Consistent with the requirements of Rider SVT, the Utilities' practice has been to hold any "Choices For You" ("CFY") customer enrollment request if there is not an actual reading of a customer's meter in over 120 days.

b) Other Parties

RGS proposed that this requirement be eliminated. RGS Ex. 1.0, 42.

c) North Shore / Peoples Gas Response

The Utilities have accepted RGS' position on this issue, so it is no longer contested. NS-PGL Ex. TZ-2.0 at 58.

d) Commission Analysis and Conclusion

The Commission finds that proposed elimination of the 120 day meter read requirement for CFY enrollment is uncontested and reasonable we approve it.

7. Meter Reading

This issue has been moved to Operating Expense, Uncontested Issue No. 8, Section III.B.8 above.

8. Automatic Meter Reading

a) Other Parties

Vanguard and Multiut argued that the availability of automatic meter reading ("AMR") addressed the Utilities' concerns about meter reading for Rider FST customers. Vanguard Ex. 1.0, 11-12; Vanguard Ex. 2.0, 11-12; Multiut Ex. 1.0, 6.

b) North Shore / Peoples Gas Response

The Utilities responded that AMR did not alleviate the larger issue of the need to better align customer usage with daily injection and withdrawal rights. NS-PGL Ex. TZ-2.0 at 6. However, in light of the Utilities' withdrawal of their proposal to eliminate Rider

FST and, in their proposed form of Rider FST, to retain the absence of a daily metering requirement, *infra*, Section X.C.1., this argument is moot.

c) Commission Analysis and Conclusion

The Commission finds that the issue raised by Vanguard and Multiut regarding automatic meter reading is moot in light of North Shore's and Peoples Gas' withdrawal of their proposal to eliminate Rider FST.

9. Billing Demand Determination

a) Other Parties

CNEG proposed that the Utilities be compelled to change their method of determining a customer's Billing Demand from being the customer's highest daily demand in therms from December to February of the most recent 12 month period to the arithmetic average of the customer's highest five daily demands in therms from December to February of the most recent 12 month period. CNEG Ex. 1.0 at 25.

b) North Shore / Peoples Gas Response

The Utilities originally opposed CNEG's proposal. NS-PGL Ex. TZ-2.0 at 46. However, they also indicated they could accept a compromise revision to the Billing Demand definition based on certain alternate tariff language proposed by CNEG. NS-PGL Ex. TZ-2.0 at 46. In rebuttal testimony, CNEG stated it was willing to accept the Utilities' compromise language on this issue. CNEG Ex. 2.0 at 34. Other Intervenors and Staff filed no testimony in connection with the proper determination of Billing Demand.

c) Commission Analysis and Conclusion

The Commission finds that North Shores' and Peoples Gas' proposed revised definition of Billing Demand is uncontested and reasonable, and therefore approves it.

10. Imbalance Trading

a) North Shore / Peoples Gas

In its original filing, Peoples Gas proposed to expand the circumstances under which imbalance trades would be allowed. PGL Ex. TZ-1.0 at 49. It proposed that trades be allowed for any movement of gas to or from a customer's Allowable Bank ("AB") for any reason, as long as (1) they net to zero within Peoples Gas' system; (2) they cannot reduce bank balances below minimum bank requirements or increase them above maximum bank requirements; (3) they are confirmed by both parties; (4) they are done via PEGASys™; and (5) they may not eliminate daily balance penalties. North Shore originally proposed identical permissible imbalance trading provisions. NS Ex. TZ-1.0 at 46-47. In rebuttal, Mr. Zack clarified that an additional condition of a permissible trade was that a customer could not trade gas in excess of the amount of its imbalance. NS-PGL Ex. TZ-2.0 at 65.

b) Commission Analysis and Conclusion

The Commission finds that North Shore's and Peoples Gas' proposals to expand the circumstances under which imbalance trades would be allowed are uncontested and reasonable, and the Commission approves them.

C. Large Volume Transportation Program

1. Rider FST

Each Utility originally proposed to eliminate its Rider FST (Full Standby Transportation), recommending that existing FST customers either take transportation service under Rider CFY or Rider SST (each as modified), or elect retail sales service. PGL-NS Ex. TZ-1.0. After objection from the transportation customers participating in this docket, the Utilities proposed to retain an alternative form of Rider FST. PGL-NS Ex. TZ-3.0 at 4. The revised Rider FST would cap a customer's daily nominations[49] at that customer's average daily use in the parallel month of the prior year, plus 0.67% (20% divided by 30) of the customer's allowable bank ("AB") of stored gas, with the customer adhering to the Utilities' end of season restrictions on storage balances. Id. at 5. The Utilities also modified their proposed changes to Rider SST (discussed later in this Order). Both FST and SST customers would have the identical end of season storage inventory requirements with the applicable Utility.

The Utilities aver that proposed Rider FST retains many of the existing features of current Rider FST. Proposed Rider FST also includes an updated Diversity Factor based on the study used to support the Rider SST Diversity Factor, several editorial changes for consistency with Rider SST, incorporation of the expanded imbalance trading rights and, based on the study used to support other administrative charges, revised administrative charges of $8.94 for Peoples Gas and $11.24 for North Shore.

The Utilities assert that their revised Rider FST incorporates suggestions made by Vanguard and Staff. Although the transportation intervenors express satisfaction with the Utilities' proposal to retain Rider FST, they object to various elements in the revised version of the Rider. Since these objections principally concern the Utilities' proposed injection and withdrawal limits and seasonal cycling requirements, we will address those matters in subsection X.C.4 of this Order, below.

Commission Conclusion

The Commission approves the Utilities' proposal to retain Rider FST for each Utility. We find that the proposed administrative charges of $11.24 for Peoples Gas and $8.94 for North Shore are supported by the evidence and are approved, as are the other revisions not otherwise modified or rejected elsewhere in this Order.

2. Rider SST

In response to other parties' criticisms during these proceedings, the Utilities modified their proposed changes to Rider SST (Selected Standby Transportation).

[49] A nomination is a quantitative declaration of intended gas delivery, at a pre-selected interval (e.g., intra-day, daily, weekly, monthly) or on an as-needed basis.

PGL-NS TZ-3.0 at 9-10. In lieu of their original proposals for daily injection and withdrawal limits, the Utilities' revised Riders SST would limit a customer's monthly injections to 20% of AB converted to a daily injection limit, but there would not be additional daily limits on a customer's withdrawals from AB beyond limits currently in effect. Because Rider SST consumption is metered daily, the Utilities set a daily injection limit rather than a limit based on an estimate of prior year's usage. The Utilities state that this will allow Rider SST customers to adjust for expected changes in consumption and still make AB injections. The revised Riders SST would have new daily and monthly injection provisions, in the form of nomination limits, similar to proposed Rider FST, while retaining the existing daily and monthly withdrawal provisions. Rider SST would also have the seasonal cycling requirements applicable to proposed Rider FST.

The transporters oppose the cycling requirements and injection limits in Rider SST. Again, the Commission will address those matters in subsection X.C.4 of this Order, below.

Commission Conclusion

As we did with respect to Rider FST, the Commission approves the Utilities' Riders SST for each Utility, except insofar as terms it contains are modified or rejected elsewhere in this Order.

3. Daily Metering Requirements

The Utilities contend that their revised proposals regarding Riders FST and SST essentially moot this issue. Customers currently served under Rider FST can continue to receive service under that Rider without daily metering. Customers currently served under Rider SST, and any customer electing to be served under Rider SST in the future, would be required to have their consumption metered daily. Staff finds this arrangement acceptable, since Rider FST customers will not have to incur meter costs and Rider SST customers will either have a meter already or will switch to SST knowing what is required.

Commission Conclusion

The Commission finds that there is no dispute left for decision.

4. Injection, Withdrawal and Cycling Requirements seasonal cycling requirements

The Utilities propose that large volume transportation customers satisfy biannual storage cycling requirements under either Rider FST or Rider SST. During the gas injection season, the Utilities would require customers to inject gas into the Utilities' storage facilities by November 30th of each year. The required injection would be 70% of aPeoples Gas's customer's (or 75% of North Shore customer's[50]) "allowable bank" -

[50] As originally proposed, North Shore's injection threshold was 85% of allowable bank. However, the Utilities, CNEG and Vanguard subsequently agreed that North Shore's seasonal injection target should

the customer's maximum daily quantity multiplied by a Utility-selected number of storage days (approximately 29 for Peoples Gas and 26 for North Shore). Tr. at 548-49 (Zack). If a customer falls short of the required threshold, the pertinent Utility would charge the customer on November 30th for the shortfall, at a price determined by the AMIP for the cost of gas at Chicago for November, plus 10%. NS-PGL Ex. TZ-3.02. Currently customers face no such requirement.

Similarly, during the gas withdrawal (or heating) season, the Utilities would require customers to withdraw gas from their storage facilities so that only 35 per cent of the "allowable bank" remains by March 31st. If the FST customers fail to reduce gas in storage to the 35% Peoples Gas threshold or the 24% North Shore threshold, the Utilities will "buy back" the excess at 90 per cent of the AMIP for the month of March. Tr. at 551 (Zack).

Each Utility presented six years of operating data to support its respective proposed storage cycling requirements. NS Ex. TZ-1.1; PGL Ex. TZ-1.1. The Utilities maintain that in each case the data show that the proposed storage cycling requirements are more favorable to large transportation customers than the storage cycling requirements applicable to each utility with respect to its leased storage services.

Multiut does not presently inject gas into storage, because it purchases gas for direct delivery to its customers, either on the spot market or from the Utilities under Rider FST. Multiut Ex. 1.0 at 3. Consequently, Multiut avers that the Utilities' proposed seasonal cycling requirements will cause it to alter its operations by requiring pre-winter gas purchases and spring withdrawals or pay a penalty for failing to do so. Multiut posits that it could be forced in the summer to purchase injection gas from the Utilities at 110% of market price, then sell that gas back to the Utilities at the end of March at 90% of market price. Thus, Multiut contends, the Utilities "could make a 20 per cent spread by buying and selling to the customer the same gas in storage." Multiut Init. Br. at 7. Furthermore, Multiut emphasizes, Section H of Rider FST allows the Utilities to restrict the customer's nomination of gas to be delivered each day. Multiut states that the Utilities have imposed such restriction during 42% of the days in 2004 through 2006. Multiut Ex. 1.0 at 5. Therefore, Multiuit concludes, the Utilities have the power to prevent customers from injecting or withdrawing gas to meet cycling requirements. On exceptions, Multiut requests exclusion from the Utilities' proposed mandatory seasonal cycling. Multiut BOE at 3.

CNEG argues that the Utilities have not shown that their proposed seasonal cycling targets are operationally necessary. CNEG acknowledges the periodic necessity to fill and empty aquifer storage fields, but asserts that it is unnecessary for transportation and sales customers to cycle their storage gas on the same seasonal schedule. "For many years PGL has been able to properly cycle its gas…to meet its own operational and seasonal requirements without any maximum or minimum storage

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be reduced to 75% of allowable bank. *E.g.*, CNEG BOE at 3-4. This intra-party agreement was linked to other elements of a multi-issue agreement among these parties, reached after distribution of the ALJs' Proposed Order.

level requirements imposed on transportation customers." CNEG Init. Br. at 16. Moreover, Peoples Gas "has never failed to properly cycle Manlove Field in spite of no cycling requirements for transportation customers." Id. In CNEG's view, the focus of seasonal cycling should continue to be on the aggregate performance of all customers (both sales and transportation), not on individual customer performance.

Additionally, CNEG questions whether the Utilities' proposed target storage inventories for November 30 and March 31 are, in fact, "soundly supported by the underlying assets of the [U]tilities." Id. at 17-18. CNEG asserts that:

> …nearly 85% of [Peoples Gas's] total storage assets have fall injection requirements that either are non-specific or less stringent than either a 70% or [formerly] 85% target. Only service under NGPL [Natural Gas Pipeline Company] Rate Schedule DSS service has a higher fall cycling target of 95%, but compliance for that target is measured during a 30-day window from October 15 to November 15. For spring withdrawal requirements, 80% of [Peoples Gas's] total storage assets have withdrawal requirements that are less stringent than the 35% and 24% proposed. Only ANR Pipeline Company's Rate Schedule FSS service has a more stringent target of 20% or less by March 31. (PGL Ex. TZ 1.0…; CNEG Cross Ex. 2 and 3 (Zack)).

Id. at 18.

IIEC, along with CNEG, dismisses the Utilities' contention that seasonal cycling requirements for transportation customers will protect the interests of sales customers. Indeed, IIEC claims, the absence of a common cycling schedule for transportation and sales customers "could actually cost sales customers money." IIEC Init. Br. at 11. That is, even though sales customers would "save some money" if transportation customers adhered to the Utilities' proposed seasonal cycling requirements, they would "save even more money." Id. *citing* IIEC Ex. 1.0 at 23-24.

The large transportation customers also disagree with the Utilities' differing cycling requirements for Peoples Gas and North Shore. They argue that the two Utilities essentially share Manlove Field, almost of which is devoted to Peoples Gas. They do not believe that the nominal distinction between corporate affiliates justifies separate cycling requirements.

The Utilities reply that they have properly cycled their storage gas in the past without the proposed cycling requirements only because they have imposed delivery restrictions on transportation customers as needed. They reiterate that their core objective is to meet their own seasonal cycling targets without being thwarted by transportation customers who take supply actions inimical to that goal. They also insist that they should not share a common cycling target, because they are separate utilities with separate distribution systems, assets and discrete storage rights.

Commission Conclusion

Seasonal Cycling Requirements

In Nicor we approved a fall injection target but not a spring withdrawal target. The Commission concluded that the former was a valid operational requirement that would not unduly burden transportation customers, but the latter was not. Nicor, Docket No. 04-0779, Order at 146. We are not persuaded to approve a different regime in these dockets. The Utilities generally assert that "the storage and standby rights of each Utility's transportation customers need to be shaped to be consistent with each Utility's individual gas supply portfolio, and each Utility needs to have an annual mechanism to adjust those rights as its individual gas supply portfolio changes." That is not enough to outweigh the considerable difficulties the seasonal cycling requirements will present for transportation customers. *E.g.*, CNEG Init. Br. at 20-24. While we are willing to subordinate those difficulties to the Utilities' operational needs during the heating season, the balance tips in the transportation customers' favor in the spring.

We note that the Utilities attempt to elide our Nicor ruling by claiming that "[t]he reason the Commission did not impose a spring withdrawal target on Nicor Gas' transportation customers is that Nicor Gas itself did not routinely operate its system in accordance with the same spring withdrawal targets which it was trying to apply to its transportation customers." PGL-NS Rep. Br. at 150. That is misleading. The Order asserts multiple reasons for our ruling, with the greater emphasis placed on the burden the spring target imposed on transportation customers.

The Commission also observes that the Utilities strongly emphasize the cycling requirements they face with respect to leased storage facilities. Without intending to minimize in any way the significance of those requirements, we see that the larger volume of stored gas managed by Peoples Gas resides in Manlove Field, where Peoples Gas establishes its own cycling schedule. Thus, most of the Utilities' own storage flexibility is constrained by the general need to recycle Manlove, not by storage leases. That fact, in turn, allows some latitude when balancing the competing and equally legitimate needs of the Utilities and the transporters.

Accordingly, injection season requirements of 70% and 75% of AB are approved for, respectively, Peoples Gas and North Shore, while seasonal withdrawal requirements are disapproved. We decline to exempt suppliers like Multiut, who prefer not to inject third-party gas into storage, from the pre-winter injection requirement. Under the terms of Rider FST, such suppliers' operations do meaningfully rely upon and affect the Utilities' gas storage management[51] and, therefore, they will not be exempted from the requirements imposed on suppliers that do inject.

[51] "Every day that the supplier delivers more gas than the FST customer consumes, the customer uses the AB. Every day that the supplier delivers less gas than the FST customer consumes, the customer uses the AB, to the extent inventory is available…[I]t is inevitable that deliveries and consumption do not match each day, and the AB and standby gas purchases are how this difference is accommodated." PGL-NS Ex. TZ-2.0 at 10. Thus, even without injection, FST customers utilize storage assets under the tariff, for excess delivery or as a source of standby gas supply.

The Commission will not require a common seasonal target for the two Utilities. They correctly demonstrate that they are separate entities with distinct profiles and tariffs.

Daily Injection Limits

As already explained, the Utilities would cap a customer's Maximum Daily Nominations ("MDNs") throughout the year at that customer's average daily use in the parallel month of the prior year, plus 0.67% (20% divided by 30) of the customer's AB. Any daily imbalance between the allowable daily nomination and actual usage would be subject to substantial imbalance account charges (10 cents per therm on a Non-Critical Day and six dollars per therm on a Supply Surplus Day).

The Utilities generally support their proposals with the proposition that they are required, due to their responsibility for the reliable functioning of their systems, to reasonably limit the prerogatives of the various customer classes, including large volume transporters.

For Rider FST, Vanguard would agree to be limited to the proposed MDNs during the months of April through October of each year. However, for the rest of the year (November-March) Vanguard recommends that a supplier's Maximum Daily Quantity ("MDQ")[52] continue to determine its maximum daily nomination. According to Vanguard, Nicor now manages its storage assets in a similar fashion, as a result of our ruling in Nicor's most recent rate case that "[t]o the extent possible, the Commission would prefer to increase rather than reduce the flexibility of customers." Vanguard Init. Br. at 3 (quoting Nicor, at 131). Vanguard proposes the same MDN limits for Rider SST.

CNEG claims that the proposed daily nomination limits "significantly diminish the value of Rider SST for transportation customers." CNEG Init. Br. at 12. Current Rider SST allows a customer to have as much as its entire MDQ delivered, and the customer can inject any excess above usage into the AB (subject to AB limits). In contrast, under revised Rider SST, if the customer's present actual usage is greater than 0.67% of its AB, then a withdrawal from storage may need to occur, rather than the injection that would have been permitted under current Rider SST. This limits the customer's ability to inject gas. "Normal imbalances on any given day may actually be larger than the allowed storage injection for the day." Id. (*citing* Tr. 787 (Rozumialski).

Moreover, CNEG charges, revised Rider SST also adversely impacts a customer when usage is below expectation. Delivered gas above 0.67% of the AB plus actual usage would be subject to an imbalance charge of $.10 per therm. The prohibition on intraday nominations to adjust for normal production and weather changes "exacerbates the problems of the proposed daily injection limits." Id.

[52] Maximum Daily Quantity is defined in the Utilities' proposed SST tariffs as the maximum amount of customer-owned gas that a customer may deliver on any day. PGL-NS Ex. TZ-3.3

Thus, CNEG initially recommended that daily injections either be limited to MDN as defined in Rider FST (but applicable year-round and not merely the April-October period as proposed by Vanguard), or remain identical to current tariffs by limiting daily injections year-round to MDQ. However, after distribution of the ALJ's Proposed Order, CNEG, Vanguard and the Utilities reached agreement (for purposes of this administrative litigation) that an MDN limit would apply under both Riders FST and SST during April through October - with MDN defined as the maximum amount of gas a customer may deliver on any day. MDN would be calculated as previously described (average daily use in the parallel month of the previous year plus .67% of the customer's AB). CNEG, Vanguard and the Utilities additionally agreed that if a large transport customer's "usage profile materially changes" from the previous year, the Utilities "would accept [the] customer['s] request[] to revise MDN and in good faith entertain agreement to a revised MDN based upon demonstrable evidence of" such material change. CNEG BOE at 4.

The IIEC and Multiut did not enter into the agreement described in the preceding paragraph. IIEC maintains that the agreement should not be adopted by the Commission for determining FST and SST customers' daily injection limits. IIEC argues that the limits are not aligned with the fluctuating business needs of IIEC end-users, and that the potential for modifying MDN suggested in the agreement will not cure that defect. IIEC RBOE at 5-6. IIEC also charges that daily nomination limits would impair customers' ability to meet injection season cycling targets. Staff's view is that the MDN provision in the agreement is appropriate for Rider FST because FST customers do not have demand meters, but not for Rider SST. Staff RBOE at 60.

The Commission readily acknowledges the serious and complex responsibilities the Utilities bear with respect to management of their storage assets. We also recognize the desire of large commercial gas end-users to manage gas supply in a manner that efficiently contributes to their enterprises. We are also committed to encouraging competitive gas supply, so that customers enjoy the benefits competition can provide. Our task is to optimally balance these interests. The above-described agreement on daily nominations is satisfactory to the Utilities and two of the three suppliers that chose to participate in these ratemaking proceedings, but the end-users represented by IIEC oppose it.

Although the IIEC arguments are largely theoretical and not supported by evidence of impairment for any particular customer, the Commission does not doubt their general validity. While IIEC end-users will not lack the gas supply their businesses need, they may have less storage control than they want. Nonetheless, while we certainly intend to promote profitable economic activity, that is an indirect objective. Our direct mandate is utility regulation. The Utilities here insist that effective and reliable storage system management requires daily nomination limits after the end of the heating season. Maximum daily injection capability diminishes from the start of the injection season until its conclusion because field pressure accumulates. PGL-NS Ex. 1.0 at 12-13. To preserve customer flexibility, we rejected the Utilities' proposed March 31 withdrawal target. As a result, the Utilities may begin the injection season already having more gas in storage than they would prefer. IIEC itself states that "if transportation customers bring in more gas in a month when the [Utilities] are also trying to fill up their fields, there could be a problem. Those would be the months May through October." IIEC Ex. 1 at 19. Ultimately, averting such problems is in the interest of IIEC end-users.

Accordingly, with regard to daily nominations specifically, the Commission will approve the terms agreed to by CNEG, Vanguard and the Utilities, quoted above, which appear reasonable[53] and achieve a balance of interests acceptable to those parties. Outside of the April-October period, the MDQ nomination benchmark will continue to apply, as it does under the Utilities' currently-filed rates.

As indicated in earlier subsections of this Order, Riders FST and SST are approved subject to our rulings in this subsection.

5. Unbundled Storage Bank ("USB")

Collectively, the IIEC, Vanguard and CNEG propose that the Utilities offer an unbundled storage service ("USB") to transportation customers[54]. These proponents stress that the Utilities have access to Manlove Field and are, therefore, capable of offering USB as an unbundled storage service. IIEC Init. Br. at 14. In fact, the Proponents note, the Utilities have already offered USB to third parties such as Merrill Lynch, and to smaller customers served under SC 2.[4] Moreover, North Shore receives its storage service from Peoples Gas at Manlove. In contrast, the Proponents emphasize, transportation customers cannot presently obtain USB from the Utilities without also acquiring the Utilities' standby service. Id. at 12-13. Furthermore, according to the Proponents, "because transportation customers can now only secure storage service if they purchase standby service…these customers will be exposed to proposed [standby rate] increases of 74% on [Peoples Gas] and 50% on [North Shore]." Id. at 13.

The Proponents' contend that their suggested formula for allocating storage to transportation customers at Manlove is "similar to a formula used by the Commission to allocate Nicor's underground storage for unbundled access" in Nicor. Id. at 14. Under the Proponents' formula (after adjustments reflecting "the diversity of transportation customers use of storage"), Peoples Gas transportation customers would receive 20 days of storage and North Shore transportation customers would receive 6 days. Id. at 15. Thus, 13.1 BCF of storage would be available to transportation customers, equaling about 37.7% of Manlove's storage capacity. Id. Transportation customers represent about 40% of the Companies' annual thru-put. Id.

[53] The agreement contemplates MDN revision in the event of material change in customer usage profile. The Commission approves this with a firm prohibition against discrimination by a Utility toward any customer or supplier (within the meaning of 220 ILCS 5/9-241), and with an unambiguous expectation that agreement to requested revision will not be unreasonably withheld.

[54] For the purposes of this subsection of the Order only, the three parties will be denominated collectively as the "Proponents."

[4] Customers must pay for Manlove storage as part of the SC 2 Rate. IIEC/CNEG/VES Ex. 1 at 6.

The Proponents also offer a formula for establishing a common USB rate for the Utilities' transportation customers. Proponents characterize the formula as "patterned after the rate format" we approved in Nicor. Id. at 16. The formula uses Manlove's total cost of service total capacity, excluding the carrying costs of top gas (because transportation customers provide their own and have no right to the Utilities' top gas without paying an additional charge). Id. Proponents' formula yields a storage charge of 0.66 cents per therm per month, which Proponents adjust down to 0.60 cents to account for the diverse storage usage characteristics among transportation customers." Id. at 17.

The Utilities assert that the proposed USB would provide USB customers "with daily injection and withdrawal rights vastly exceeding the capabilities of Manlove," thereby causing the Utilities' sales customers "to subsidize the USB service." PGL-NS Init. Br. at 196-97. The Utilities further argue that the USB proposal would "make it more difficult for the Utilities to manage their systems for the benefit of all their customers." Id. at 197. The Utilities also believe it is significant that they are each separate entities with "different gas storage rights," and that North Shore has no storage asset to unbundle because it does not own Manlove or any other storage field. Id.

Staff also opposes the USB proposal, because it involves only Manlove Field, which Staff views at the Utilities' lowest cost storage asset. Staff Ex. 24.0 at 13. Staff avers that the storage available to transport customers should equitably reflect the cost and availability of *all* storage resources that the Utilities own or lease, so that other customer groups do not have to pay "rates that reflect higher cost [storage] resources. Id. at 13.

Commission Conclusion

The Commission will not approve the USB proposal. We agree that the proposal is tied to the Utilities' lowest cost storage asset and would benefit large transportation customers disproportionately, to the detriment of sales customers. Additionally, we cannot find that record evidence disproves the Utilities' assertion that the USB proposal will interfere with their ability to manage their storage assets for the benefit of all customers. The proponents of USB request reservation of a substantial portion of Manlove Field in proceedings in which the Utilities are asserting the need for greater control of its storage assets[55]. Without more, the Commission declines to disregard the Utilities' insistence that the USB proposal will unduly burden their storage operations.

[55] The Commission notes that, on exceptions, the IIEC asserts that Peoples Gas offered unbundled storage to Merrill Lynch (and, in part for that reason, should be ordered to implement USB here). IIEC BOE at 6 & 7. Peoples Gas responds, as it did with prefiled evidence, that the Merrill Lynch arrangement involved a capacity release of storage rights PGL obtained from others (and which transportation customers could have, but did not, bid for). PGL-NS RBOE at 5 (*citing* PGL-NS Ex. TZ 2.0 at 16-17). Thus, the Merrill Lynch transaction does not demonstrate that the Utilities can readily offer a tariffed storage service (particularly a service tied to Manlove Field) to transportation customers generally.

6. Rider P-Pooling

a) Pool size limits

The Utilities each proposed to increase the maximum pool size under Rider P from 150 to 200 accounts. NS Ex. TZ-1.0 at 43; PGL Ex. TZ-1.0 at 45. In response, Vanguard proposed that the pool size limit be increased further, to 300 accounts. Vanguard Ex. 1.0 at 5-6; Vanguard Ex. 2.0 at 5-6[56]. CNEG proposed that the pool size limit be eliminated entirely. CNEG-Gas Ex. 1.0 at 18. Staff also believes that the pool size limit should be eliminated entirely. Staff Ex. 24.0 at 21.

The Utilities contend that their recommended limit is dictated by "administrative and billing system reasons." PGL Ex. TZ-2.0 at 35. "[S]ystem features require that all sub-accounts [in a pool] be billed before the pool bills. If one sub-account cannot be billed as a result of a billing exception, the pool cannot bill. Allowing more accounts…will increase the time needed to review and resolve billing exceptions and bill a supplier pool." Id.

CNEG argues that the key consideration is whether removing the pooling cap would increase costs, and further avers that the Utilities have not proven such cost increase. CNEG Init. Br. at 28. Indeed, CNEG claims that expanded pool sizing would save administrative costs for the Utilities. Id. at 29. CNEG also identifies several utilities that do not cap the number of accounts in a customer pool. Id. at 28.

Commission Conclusion

None of the Utilities' opponents on this issue successfully refute the Utilities' assertion that expanded pool membership increases the likelihood of delay-causing, account-specific billing issues *within the enlarged pool*. To the contrary, Vanguard accepts this proposition. Vanguard Ex. 3 at 5. On the other hand, the Utilities do not demonstrate why the potential delay associated with 200 accounts is acceptable, while the delay associated with a larger number is not. The Utilities are presumably attempting to strike a balance between reasonably prompt billing (which is likely to make receipt of revenues correspondingly prompt) and the advantages all stakeholders derive from pooling. The Commission agrees that a balance should be achieved and, accordingly, we reject the suggestion to remove the cap altogether.

However, without evidence compelling us to strike the balance at 200 accounts, the Commission will place the balance higher - at the 300 accounts recommended by Vanguard. It is implicit in the Utilities' own proposal that they can comfortably handle larger pools than they have previously, and we agree with Staff witness Reardon that "pools provide economies to marketers that can result in lower prices for their customers." Staff Ex. 24.0 at 20. Accordingly, to promote the latter outcome, the Commission selects a pool limit that, based on the record before us, will not unduly burden any stakeholder.

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[56] Ironically, in Nicor Gas Company's most recent rate case, Vanguard argued that Nicor Gas should increase its pool size limit from 50 accounts to 150 accounts, using the existence of PGL's Gas' Rider P pool size limit of 150 accounts as support for its argument. Nicor, Docket No. 04-0779, Order, at 174.

b) “Super-pooling”

CNEG and Vanguard recommend approval of super-pooling, which allows aggregation of all of a supplier’s customer pools into a single pool for certain purposes, such as measuring compliance with the Utilities’ inventory and daily balance requirements. These intervenors also request that their individual, or “stand-alone,” accounts be included in a super-pool.

After initially opposing super-pooling, the Utilities agreed to accept super-pooling if it were used solely for the purpose of determining whether a supplier meets biannual cycling requirements and if stand-alone (non-pooled) customers were excluded. NS-PGL Ex. TZ-3.0 at 14. Vanguard would accept the Utilities’ revised position, though it would prefer to include stand-alone accounts in super-pools. Vanguard Ex. 3 at 4. CNEG continues to urge that stand-alone accounts be added to super-pools and that super-pooling apply to critical and supply surplus days. Staff expresses “concerns” about super-pooling, but, “does not oppose it” insofar as it is acceptable to the utilities. Staff Init. Br. at 258.

Commission Conclusion

The Commission approved super-pooling in Nicor, to “mitigate the adverse impact of cycling requirements adopted” in that case. Nicor, Docket No. 04-0779, at 149. We see no reason to chart a different course in the present case, particularly when the Utilities are willing to accept super-pooling associated with their annual cycling requirements.

The Commission also concludes that stand-alone accounts can be included in a gas marketer’s super-pool. Given the Utilities’ assertion that the underlying intention of their cycling regime is to achieve *system-wide* objectives (and not to impose penalties on individual accounts), fragmentation of a marketer’s stand-alone accounts is, at the least, unnecessary. The problem posed for the Utilities by inclusion of stand-alone accounts in super-pools is really a billing system problem. To alleviate that concern, we adopt CNEG’s recommendation that a marketer or supplier cannot include in its super-pool any stand-alone customer that has purchased gas supply from another source during any month in which the marketer’s or supplier’s cycling compliance is assessed.

With inclusion of stand-alone customers, we cannot agree with CNEG that super-pooling should be utilized for assessing compliance with applicable limitations on critical days or supply surplus days. CNEG’s rationale - that critical days and supply surplus days are essentially like annual cycling compliance milestones, because they “are not regular, ongoing circumstances” CNEG Init. Br. at 31 - is both incorrect and inimical to CNEG’s own cause. By its terms, annual cycling compliance will be quite regular and, per our ruling here, will occur only once each year. Accordingly, for purposes of calculating annual cycling compliance, the Utilities can predictably employ an “ad hoc process that will run tangentially to their existing processing and, therefore will not require [structural modifications to billing systems].” PGL Ex. TZ-3.0 at 16. In contrast, critical and supply surplus days are temporally and quantitatively erratic. To apply super-pooling to such unpredictable events, when the appropriate treatment of stand-alone accounts will have to be determined each time, would present the billing system complexity the Utilities reasonably want to avoid[57]. Id. at 14. Moreover, it would likely and excessively entangle the utilities in the relationship between suppliers and individual customers with respect to allocation of daily gas deliveries. Id. at 17.

CNEG proposes a mechanism for apportioning responsibility among super-pool members when the marketer or supplier is out of compliance with inventory requirements. CNEG Ex. 2.0 at 8-9. The proposed apportionment would be based upon the percentage by which an individual pool contributed to the total non-compliance margin. Id. The Utilities state that CNEG's proposal is acceptable. Zack Ex. 3.0 at 16. The Commission concurs.

c) Permitting Customers With Different Selected Standby Percentages ("SSP") to Be in the Same Pool

CNEG proposes that customers with different SSPs be allowed into the same supplier pool. CNEG Ex. 1.0 at 15. The Utilities would accept that proposal if it is implemented as follows: 1) a pool's MDQ would be the summation of the underlying customer (contract) MDQs, and 2) a pool's SSP would be the weighted average of its customers' (contract) SSPs. NS-PGL Ex. TZ 2.0 at 40. The Utilities provide a detailed example of how these guidelines would be applied. Id. at 40. CNEG states that the Utilities' implementation scheme is reasonable. CNEG Ex. 2.0 at 29. No party opposes either CNEG's proposal to include differing SSPs in common pools or the Utilities' proposed implementation of that proposal. Id. Therefore, CNEG's proposal and the Utilities' recommended implementation rules are approved.

7. Operational Issues

a) Intra Day Allocations and Intra Day Nominations

CNEG requests that we require the Utilities to accept intraday nominations for gas delivery. CNEG asserts that intraday nominations are standard practice, to varying degrees, throughout the North American natural gas industry. They say intraday nominations facilitate adjustments for unexpected events such as weather or production changes, or pipeline or utility service disruptions. Peoples Gas itself is allowed to make intraday adjustments, and allows intraday nominations on a select basis. Accordingly, CNEG insists, Peoples Gas should be required to universally permit intraday nominations for all transportation customers who represent over 40% of annual throughput, particularly given Peoples Gas' proposed storage restrictions. CNEG also underscore that the rates paid by transportation customers include the cost of leased storage services, which enable Peoples Gas to make intraday nominations.

The Utilities propose that a customer or supplier with more than one contract or pool be permitted, on an intra-day basis, to re-allocate deliveries between or among its

[57] On exceptions, CNEG argues that the Utilities could simply use the same process on critical and supply surplus days that they employ for injection season compliance. CNEG BOE at 7. That is correct, but misses the point. Since stand-alone accounts cannot be included whenever they use another supply source, the Utilities will have to determine their status for each critical or surplus day.

contracts or pools. They maintain that this will enable suppliers to reallocate gas among their contracts, to offset potential gas deficiencies and avoid penalties.

However, the Utilities are not willing to accept amended gas nominations during the course of a day. They stress that they manage an entire utility system (including supplier of last resort obligations) and must match demand with supply, despite a dynamic demand profile, on a real time basis. They say an obligation to accept intraday nominations from transporters could cause them to scramble to match supply with consumption, and then have to adjust their own supply to do so. They do not want to have to shed supply during a warm winter day while marketers are trying to increase their own supply because prices are low. They add that while intra-day nominations are industry standard for interstate pipelines, they certainly are not standard for local gas distribution companies.

The Utilities suggest caution about CNEG's comparisons with the tariffs of utilities that purportedly allow intraday nominations. They point out that the actual tariff of one of those utilities revealed that suppliers must exactly match deliveries and consumption on a daily basis, making intraday nominations more appropriate.

Commission Conclusion

The Commission finds that the Utilities' proposals to allow intraday allocations are reasonable and will provide benefits to the Utilities' transportation customers without detriment to the Utilities or their sales customers. Therefore the Commission approves the Utilities' proposals to allow intraday allocations.

The Commission also finds that CNEG's proposal to permit intraday nominations by large volume gas transporters could make it substantially more difficult to balance the Utilities' systems on a real time basis, to the potential harm of sales and other transportation customers. The Commission believes that the Utilities' nomination procedures, along with the related modifications and intra-pool allocations mandated by this Order, provide sufficient flexibility for the transporters. Therefore, we will not compel the Utilities to accept intraday nominations from large volume gas transporters.

b) Delivery Restrictions

Currently, during a delivery restriction, the subsequent day's delivery is limited to the prior day volume delivered. In CNEG's view, this is contrary to the utility's needs. Even though it would benefit the utility for a supplier to reduce deliveries, and perhaps sell some gas, the supplier will remain at the higher delivery volume and inject the unused gas into storage, additionally stressing the system. CNEG explains that the supplier must do this because, if it reduces its delivery to what it expects may actually be consumed, it is then prevented from later increasing deliveries back to more normal volumes (i.e. original baseload volume purchased for the entire month) until the delivery restriction is lifted. By reducing delivery volumes, a supplier risks being unable to deliver the gas volume necessary during subsequent days of the delivery restriction if usage returns to more normal levels. Moreover, the supplier will be forced to continue to sell gas each day during the restriction, even if it no longer wants to. This paradox occurs, CNEG concludes, because delivery restrictions do not correlate to usage, but rather are tied to prior day deliveries which can range from a fraction of actual usage to multiples of daily usage.

CNEG proposes alternatives. It suggests that instead of using prior day deliveries for limiting subsequent day deliveries, the criteria should be usage-based (such as average daily use for the month, or the same month in the prior year, or customer MDQ) plus a storage component. Or Peoples Gas could formalize a procedure for negotiating with Peoples Gas on a case-by-case basis to impose a limited-time reduction in delivered volume with a guarantee that subsequent deliveries could return to the required delivered baseload volume, even while a restriction remains. CNEG notes that Peoples Gas already works out such arrangements, but without a governing tariff provision.

The Utilities reply that they impose delivery restrictions only when customer deliveries are disproportionate to customer consumption requirements. The Utilities recognize that the restrictions can be problematic for transportation customers, but emphasize the daily need to balance their systems, which makes delivery restrictions necessary at times. The Utilities assert that informal case-by-case negotiations are sufficient to enable a supplier to return to required baseload volume after a reduction, even while a delivery restriction continues.

Commission Conclusion

The Commission does not question that that there are times when the Utilities must impose delivery restrictions to balance their systems. We do not perceive CNEG to question that need either. Rather, CNEG seeks a solution for a collateral adverse consequence of imposing necessary restrictions. In turn, the Utilities do not question that the adverse consequence occurs. Indeed, they acknowledge working informally with transporters to alleviate the problem rationally. Accordingly, the real issue is whether to formalize the process for permitting transportation customers to return to baseload volume after a reduction, prior to termination of the delivery restriction. The Commission prefers a formal recognition of the process, to preclude discrimination and eliminate ambiguity for all stakeholders. Therefore, we direct the Utilities to create a tariff provision explicitly authorizing what has thus far been informal. The Utilities can accomplish this unilaterally, acting in good faith, and need not consult with customers regarding the text.

8. Other Large Volume Transportation Issues

a) Accounting for Trading and Storage Activity

Vanguard requests that the Utilities be directed to reinstate certain accounting practices the Utilities used before the year 2000. Vanguard asserts that the Utilities are failing to properly account for imbalance trades, new accounts added to pools and re-billed customers.

The Utilities respond that no other customer or supplier has presented the same criticisms and that no one, including Vanguard, has claimed harm as a result of the Utilities' accounting. The Utilities assert that the subject accounting practices are appropriate in light of practical administrative issues. NS-PGL Ex. TZ-2.0.

Commission Conclusion

The Commission will not resolve this dispute by ordering the Utilities to revise their accounting practices concerning imbalance traded gas and storage transfer gas. Vanguard's frustration is evident, but the absence of wider interest in this issue by other alternative suppliers does cause us to withhold action. The accounting practices Vanguard would resurrect were jettisoned approximately eight years ago, and we would expect greater industry concern if customers were actually harmed during that interval. Furthermore, the Utilities' purported accounting deficiencies are not described with sufficient granularity to justify prohibiting them.

b) Excess Bank and Critical Surplus Day Unauthorized Overrun Charges

The Utilities seek continued authority to levy an Excess Bank Charge of $0.10 per therm and a Critical Surplus Day Unauthorized Overrun Charge of $6.00 per therm. They state that the Excess Bank Charge is to deter customers from delivering gas in quantities above the customer's total AB capacity. They argue that, without the charge, a customer could have inventory substantially above AB without incurring any financial penalty. Similarly, the Utilities say, the Critical Surplus Day Unauthorized Overrun Charge is to keep transportation customer supply equal to consumption on days when critical excess of supply is coming into the Utilities' systems.

It is not clear that any party opposes these overrun charges *per se*. Although they are frequently mentioned by other parties, such discussion generally occurs in the context of quantifying the potential penalty for contravening one of the limitations proposed by the Utilities.

Commission Conclusion

The Commission finds that the Utilities' existing Excess Bank Charge of $0.10 per therm and Critical Surplus Day Unauthorized Overrun Charge of $6.00 per therm are reasonable incentives for transporters to avoid gas deliveries in excess of total AB and to keep supply equal to consumption on days when a critical excess of supply is entering the Utilities' systems. Therefore, the Commission authorizes the Utilities to continue charging their existing Excess Bank Charge Critical Surplus Day Unauthorized Overrun Charge.

c) Cash-outs Index

The Utilities seek authority to compel a customer to buy gas from the Utilities at 110% of the AMIP, and to sell gas to the Utilities at 90% of AMIP, when such customer fails to comply with the Utilities' end-of season-storage inventory requirements. They characterize these provisions as reasonable incentives to compliance. They note that the costs and revenues of these purchases and sales are accounted for in Rider 2, Gas Charge, so there is no financial benefit to the Utilities from this pricing structure.

Multiut considers these purchase and sale provisions as penalties. Multiut does not currently inject gas into storage, and it contends that the AMIP provisions will cause it to purchase gas in the summer. Nevertheless, we have approved the Utilities' injection season cycling requirement as a reasonable storage management mechanism, so we will also approve the AMIP provision that promotes compliance with that mechanism. We note that the potential purchase and sale of the same gas that Multiut predicted cannot occur, given our disapproval of the withdrawal season cycling requirement.

Commission Conclusion

The AMIP provision is approved for the injection season and rejected for the withdrawal season.

d) Receipt of Service Classification, Rider, AB, MDQ, and SSP Information

CNEG requests that certain customer information (Receipt of Service Classification, Rider AB, MDQ, and SSP Information) be made available via PEGASys™, the Utilities' electronic bulletin board system, once the supplier obtains customer authorization, even if that occurs prior to customer enrollment by the supplier. Vanguard makes the same request, emphasizing that the pertinent information is "not sensitive data related to customer payment history." Vanguard Init. Br. at 9. Vanguard also underscores that a supplier requesting the information is obliged to sign the Utilities' "Customer Usage Data Contract" demonstrating its agreement to obtain customer approval.

The Utilities are willing to make these data available on PEGASys™ at the time of customer enrollment or if the supplier signs the "Customer Usage Data Contract," but with the proviso that the data are made available only in connection with the Utilities' large volume transportation programs. PGL-NS Ex. TZ-3.0.

Commission Conclusion

The Commission is not entirely certain about what disputes remain with regard to access to the subject customer information. The parties' briefs indicate they have moved toward agreement. Nonetheless, to provide clarity to the stakeholders, we will require that the Utilities make available Service Classification, Rider, AB, MDQ and SSP customer information, via PEGASys™, to any large volume transportation supplier that has received the customer's prior approval to obtain consumption history. The supplier need not have already enrolled the customer – the key is prior customer consent. The Commission thus approves Vanguard's proposal on this issue, although we limit our approval to the data of large volume customers, who do not have the same privacy concerns as residential and other small-volume customers.

D. Small Volume Transportation Program (Choices for YouSM or "CFY")

The RGS are alternative retail gas suppliers to customers of varying size and gas consumption. Their focus in these proceedings is the Utilities' Choices For You ("CFY") program, by which the RGS supply gas service to residential and small commercial customers. The RGS purchase gas for those customers and the Utilities receive and deliver it via their distribution system. This process is governed by two riders in the Utilities' tariffs - Rider SVT, Small volume Transportation Service, and Rider AGG, Aggregation Service. CFY suppliers currently pay an Aggregator Balancing Gas Charge ("ABGC"), associated with Rider SVT, which is designed to recover the cost of off-system gas storage and balancing services. There is also an on-system (i.e., Manlove Field) storage component in the base rates CFY suppliers pay.

1. Storage Rights and Aggregation Rights

a) Specific Allocation of Storage Rights and Costs to CFY Customers and Suppliers (Including the RGS' proposed Rider AGG)

The RGS maintain that the Utilities recover costs through the ABGC that are "excessive relative to the storage rights that CFY suppliers receive [and that, consequently] CFY suppliers and their customers are essentially subsidizing sales service customers." RGS Init. Br. at 7. "The [Utilities'] method for allocating storage rights fails to deliver the appropriate amount of monthly and daily withdrawal and injection rights and seasonal hedging associated with the storage assets that are allocated to CFY." Id. at 8. The RGS want greater storage rights or, as a secondary alternative, recallable transfer of the Utilities' off-system storage and transportation rights[58] (and, as a tertiary alternative, reduction or elimination of the ABGC).

Accordingly, in their proposed rider AGG (RGS Ex. 2.1), the RGS first propose daily withdrawal and injection parameters for the winter and summer periods, ostensibly to equalize the daily and monthly storage rights of bundled sales and CFY customers. By RGS' calculations, CFY suppliers' annual allocation of storage capacity would be 30.985% and 39% of their customers' annual usage on, respectively, the North Shore and Peoples Gas systems. CFY suppliers' daily withdrawal rights during the withdrawal period (November through March) would be 54.79% and 65.93% of their customers' peak day demand on, respectively, North Shore's and Peoples Gas's systems. During the injection period (April through October), CFY suppliers' daily withdrawal rights would be 19.7% of their customers' peak day demand on both North Shore's and Peoples Gas's systems. Id. at 10-11.

The RGS maintain that their proposed storage allocation method is "consistent with the allocation of storage capacity to competitive suppliers in Nicor's Rider 16, Supplier Aggregation Service, which defines the delivery parameters for suppliers serving small volume transportation customers in Nicor's service territory."[59] Id. at 11. The RGS recommend that the Utilities use their proposal "as a starting point to develop a storage and delivery program for CFY suppliers and customers that mirrors Nicor's Rider 16." Id. The RGS also propose to revise the Utilities' Rider AGG to include monthly storage targets, which would replace the current month-end delivery tolerance

[58] The RGS propose other alternatives as well, each intended to increase the storage rights (or decrease the storage costs) of CFY suppliers. We address those alternatives where appropriate in other subsections within Section X.D. of this Order.

[59] The RGS state that their proposal and Nicor's storage allocation differ only insofar as the Utilities have both their own (Manlove) and leased storage. RGS Init. Br. at 9.

in that rider. The RGS's "Nicor-like" storage program would not involve contractual release of on-system or off-system assets to RGS suppliers or their customers, who would continue to pay for storage through base rates and the ABGC. Id. Although the Utilities note that the RGS's proposed storage targets for the winter months "provide substantially wider ranges than those in the Nicor Gas rider," PGL-NS Init. Br. at 208, the RGS reply that the storage assets "that CFY suppliers and customers pay for support wider storage targets than those in Nicor's Rider 16." RGS Init. Br. at 15.

The Utilities counter that they, not CFY customers, have to forecast, receive, deliver, store and balance gas supply every day. Therefore, they assert, their storage and delivery allocations for CFY customers reflect their overall objective of aligning the storage and delivery rights they own or procure with the correlative rights they provide others. More specifically, the Utilities argue, first, that the gas consumption of CFY customers is not metered daily, so there is no way to verify that CFY supplier injections and withdrawals are within the RGS' daily parameters. PGL-NS Init. Br. at 206. Second, the Utilities point out, the RGS' proposal uses peak day maximum capabilities, even though the Utilities' maximum injection and withdrawal capabilities diminish over the course of injection and withdrawal seasons. Id. Third, RGS's proposal was based on data from 2006, a single, unusually warm year. Id. Fourth, while the RGS proposal refers to monthly injection and withdrawal rights, the proposal itself does not quantify those monthly rights. Id.

With respect to RGS' selection of data from an atypically warm year, the RGS generally declare that they "would be willing to accept an allocation of storage rights using data from additional years." RGS Ex. 2.0 at 6. However, they offered no specifics, so the record does not contain RGS calculations using what RGS believes to be more typical weather data. Thus, the Commission has no basis for assessing the reasonableness of the result of altering the weather-related data in the RGS' proposal. The RGS also assert that, contrary to the Utilities' claim, the revised RGS proposal, in RGS Ex. 2.1 quantifies monthly injection and withdrawal rights. RGS BOE at 11. The RGS are correct.

Ultimately, the parties' arguments frame this question – can the additional storage flexibility sought by the RGS be accommodated by the Utilities' storage assets, along with the Utilities' obligations to their entire customer base? Regarding the magnitude of their storage assets, the Utilities underscore the diminution of their "storage and injection and withdrawal capabilities as the applicable injection or withdrawal season runs its course." PGL-NS Rep. Br. at 160. With respect to their overall obligations, the Utilities maintain that they, "rather than the CFY supplier, are responsible for handling CFY customer consumption changes as a result of weather changes and forecasting error under the CFY program." Id. The RGS rejoin that the CFY supplier has ultimate responsibility for serving CFY customers[60]. RGS BOE at 17.

[60] The respective responsibilities of the Utilities and CFY suppliers are not actually unclear. CFY suppliers bear responsibility for supplying their customers' fuel demand. The Utilities forecast likely CFY customer demand in order to manage daily deliveries. CFY suppliers have to supply the forecasted fuel

In effect, the parties perceive gas storage as a zero-sum game, in which the modicum of control (or "flexibility") at issue here will either remain with the Utilities or be transferred to the CFY supplier.

Additionally, the RGS charge that the Utilities offer large volume transportation tariffs that furnish "far greater flexibility" than is contemplated under the RGS proposal. RGS Init. Br. at 15. On exceptions, they enumerate several attributes of Rider FST that the RGS believe accord substantially greater storage and delivery rights to large volume customers than the rights given CFY customers under Rider AGG. RGS BOE at 10, 12. The Utilities reply that the two riders are simply "very different services." PGL-NS RBOE at 89. Staff shares this view. Staff RBOE at 62.

Commission Conclusion

Like the RGS, large volume customers are also demanding more storage flexibility in these proceedings (*e.g*., through an unbundled storage service), while the Utilities themselves are seeking greater control of their storage assets. Although none of these efforts are inappropriate, simply reflecting commercial enterprises pursuing their interests, the Utilities storage resources are, in fact, finite, and the Utilities do have the responsibility of providing enough storage and delivery for every stakeholder, even under harsh weather conditions. As the RGS recognize, under their proposed rider, the Utilities "would remain the contract entity for off-system storage and maintain physical operation of on-system assets." RGS Init. Br. at 11.

The Commission is unwilling to approve RGS' proposed Rider AGG. The RGS' responses to the Utilities' system management concerns are insufficient to justify transferring more storage flexibility to CFY suppliers and customers in the manner proposed. The RGS miss the point when they assert that the Utilities' "estimate of daily customer consumption is a substitute for daily metering." Id. at 13. The Utilities are concerned about the inability to verify, without daily metering, the *actual usage* of CFY customers, not their *estimated* usage. Nonetheless, RGS emphasizes, the Utilities' sales customers also lack daily metering. But the Utilities do the forecasting and balancing for both CFY and sales customers (and purchase gas for sales customers accordingly). Thus, the Utilities effectively control the deliveries for CFY and sales customers alike, and are not granting sales customers more delivery flexibility than CFY customers[61].

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demand for delivery (whether from third-parties, the Utilities or storage), and the Utilities are obliged to deliver it to CFY customers. When actual demand varies from the forecast, CFY suppliers still have to meet demand or make accommodation for excess, and the Utilities still have to deliver what is demanded and manage their storage and delivery systems.

[61] On exceptions, the RGS assert they are not disputing the Utilities' allocation of "*storage capacity*," but their allocation of "*delivery rights.*" RGS BOE at 4 (emphasis in original).

Additionally, while neither CFY customers (whom RGS claims[62] constitute about 4% of the Utilities system load) or Rider FST accounts (which "comprise 6.694% of the total system delivery for [Peoples Gas]," Vanguard Ex. 3 at 7), have daily meters, Rider FST, but not Rider AGG, contains the following remedial provision in the event of customer abuse of delivery rights:

> The [Utility] reserves the right to limit the daily and monthly volumes of customer-owned gas delivered for the customer's account to the [Utility] when, in the [Utility's] sole judgment, the customer's deliveries are excessive in relation to the customer's gas requirements and may cause an adverse affect on system operations.

PGL-NS Ex. TZ-3.2.

Also, while we agree with the RGS that the Utilities' speculative scenario of CFY suppliers depleting their entire inventory by mid-December is commercially unreasonable (id. at 15) some of the RGS' proposed winter minima (15% of total storage *capacity* at the end of January, zero in February) (PGL-NS Init. Br. at 208) are scarcely better. The Utilities would still need to manage delivery, storage, and, perhaps, withdraw their own stored gas to meet CFY customers' heating requirements. Moreover, despite characterizing their proposal as "Nicor-like," the RGS acknowledge that their proposal affords CFY more storage flexibility than does Nicor's scheme. RGS Init. Br. at 15. RGS's explanation that the Utilities' storage assets "support wider storage targets" than Nicor's is unsupported by evidence or even a description of the differences.

As for the differences between Rider FST and Rider AGG, large industrial customers present different challenges for the Utilities' systems than do residential and small commercial customers. As the RGS acknowledge, "[CFY] customers (residential and small commercial) use gas mostly for heating and do not have level year-round requirements." RGS Ex. 2.0 at 7. Many large industrial customers use gas year-round in their production processes or to make electric power and, consequently, have very different load profiles than CFY customers. Furthermore, Rider FST is designed for *end-user* customers, while Rider AGG is intended for *suppliers* to end-users[63]. Without addressing the differences in detail – since the RGS did not address them at all – the Utilities' rights and responsibilities[64], regarding, respectively, end-users and aggregators, are not the same. Additionally, Rider FST concerns standby service, purchased by FST customers, in part, to obtain storage rights different from those available to CFY and sales customers. Rider AGG has no standby provision. Thus,

[62] At RGS BOE at 16, RGS cites to RGS Ex. 2.0 at 9 for this statistic, which does not appear anywhere in RGS Ex. 2.0.
[63] Rider SVT applies directly to CFY customers.
[64] For context, it is the Commission's experience that residential end-users have little interest in how gas storage is allocated or accessed (and could do nothing directly about if they did have interest); they focus primarily on retail price for home heating. Large industrial customers, on the other hand, typically engage in sophisticated fuel management, including planned reliance on storage.

Rider FST end-user customers, but not Rider AGG suppliers, can demand delivery of Utility gas, which affects Utility storage and balancing. In sum, The Utilities do not have to manage storage and delivery identically for all customer types (although the rates for all customers must be appropriately cost-based).

b) Aggregation Balancing Gas Charge (ABGC)

As noted above, the ABGC is a monthly charge through which the Utilities recover the costs of off-system storage and daily balancing service from CFY customers. It is recalculated monthly. The Utilities propose to assess the ABGC directly to CFY customers instead of to CFY suppliers. PGL-NS Ex. TZ-1.0. CFY suppliers have requested this change because fluctuations in the ABGC have made it difficult for them to offer fixed rate quotes to customers. No party opposes assessing the ABGC directly to CFY customers.

However, the RGS assert that if CFY suppliers' storage rights are not put on par with sales customers' storage rights in the manner the RGS seek, "the costs that flow through the ABGC need to be significantly reduced or the ABGC needs to be eliminated altogether…CFY suppliers and customers are paying the exact same storage related costs as…sales service customers." RGS Init. Br. at 10. Thus, as the RGS see it, they pay as much through the ABGC as sales customers pay through the Non-Commodity Gas Charge ("NCGC")[65] component of the Gas Charge, but receive inferior storage rights.

The Utilities reply that they incur costs to provide storage and daily balancing services to CFY customers, based on the firm storage and related transportation services the Utilities purchase from ANR Pipeline Company ("ANR") and Natural Gas Pipeline Company of America ("NGPL"). The Utilities aver that they could not provide such services for CFY suppliers unless these costs are incurred. They maintain that there "is no reason any customer class should get free balancing and storage service from the Utilities." PGL-NS Init. Br. at 209. The RGS respond that "the of…balancing…is only worth fractions of a cent per therm."[66] RGS BOE at 2.

Commission Conclusion

The Commission approves the proposal to directly charge the ABGC to consumers, who are apparently paying that charge indirectly anyway, through their CFY charges.

We will not reduce or eliminate the ABGC. Balancing service is provided in return for payment of that charge. As the Utilities state, "deliveries and requirements will vary on a daily basis. Under CFY, the Utilities assume responsibility for daily balancing…and not requiring daily metering." PGL Ex. TZ 1.0 at 49. With regard to the

[65] As the RGS describe it, "[t]he difference between the NCGC and the ABGC is that the ABGC is designed to exclude the cost of interstate pipeline transportation necessary to support sales service." RGS Init. Br. at 10. The Utilities' tariff language is as follows: "This charge is equivalent to the NCGC, less any costs not associated with balancing or storage." PGL Ex. VG-1.1 at 29.

[66] Peoples Gas's average ABGC over the 12 months ending in July 2007 was 3.46 cents/therm. PGL-NS Ex. TZ-2.0 at 50.

off-system storage component of the ABGC, CFY suppliers are certainly receiving such services. *E.g.*, id., at 50. What the RGS do not receive, to a degree they would prefer, is control over those services. "Suppliers are paying the ABGC and do not want the [Utilities] to control decisions concerning the underlying storage and balancing assets." RGS Ex. 2.0 at 10. Such control issues are addressed in connection with RGS's proposed Rider AGG (above) and with pipeline capacity assignment (below). The ABGC is an appropriately cost-based rate for which the Utilities supply approved services, and we will not diminish it as a remedy for purportedly insufficient control of the underlying assets.

c) Pipeline Capacity Assignment

In the event that their proposed Rider AGG is rejected (as it is, above), the RGS recommend that we direct the Utilities to release "capacity associated with the assets that flow through the ABGC, [which]…include off-system leased storage assets and the pipeline capacity necessary to deliver gas from those storage assets to the [Utilities]." RGS Init. Br. at 17. More particularly, the Utilities would "release storage capacity on a one-year recallable basis and pipeline capacity on a month-to-month recallable basis." Id. In other words, the RGS and other CFY suppliers would, in practical effect, sublease the storage and pipeline capacity that the Utilities lease from ANR and NGPL[67] and the Utilities could choose to "recall," or use, any storage or pipeline capacity the CFY supplier elected not to use. RGS lists three other utilities that offer capacity release options. RGS Ex. 2.0 at 9.

The Utilities counter that the capacity release process "would require participation in one or more interstate pipeline capacity release programs…[that] generally are subject to posting and bidding." PGL-NS Ex TZ-2.0 at 49. Accordingly, they argue that "releasing relatively small amounts of capacity to suppliers for customer pools that change monthly would be" administratively burdensome. Id. Additionally, the Utilities discount the usefulness of the recall rights the RGS would attach to capacity release. "By the time the Utilities discover that gas is not being delivered, they have missed the timely nomination deadline…purchasing gas after an intra-day recall is relatively difficult and costly." Id. Furthermore, the Utilities allege, capacity release, like RGS' other proposals, lessens the Utilities' control over the storage assets they manage for all customers. PGL-NS Ex. TZ-3.0 at 28.

Commission Conclusion

The Commission will not require capacity release. The principal response of the RGS to the Utilities' explanation of excessive administrative burden is to name a handful of gas utilities that offer capacity release. The actual offerings of those utilities are not described and, indeed, RGS' own proposal is not fleshed out (in contrast to the RGS' proposed Rider AGG). We are persuaded by the Utilities testimony (summarized

[67] RGS alternatively suggests a permutation on capacity release, by which the CFY suppliers would receive storage services based on the tariff rights the Utilities receive from off-system pipelines, with actual storage provided by Peoples Gas at Manlove. Thus, CFY suppliers would get Manlove storage under the terms and conditions applicable to off-system storage.

above) that capacity release involves a degree of complexity that the RGS have simply not addressed, either through evidence or their post-hearing arguments. This is not to say that capacity release is (or is not) an unwelcome idea. But the record presented here does not, by a considerable degree, furnish the requisite detail that could permit the Commission to impose a capacity release requirement.

d) Customer Migration

Customer migration occurs when a customer switches from one supplier to another, from the Utilities to a supplier, or from a supplier to the Utilities. RGS Ex. 2.0 at 10. The amount of seasonal storage capacity allocated to each supplier is based on the estimated load of the customers served by that supplier. Under the Utilities' current CFY storage program, the amount of available storage capacity allocated to each supplier is fixed prior to the start of the withdrawal period in November. The RGS assert that this can leave them with insufficient storage if a significant number of customers migrate to them after the withdrawal begins. A supplier's load would increase, but the amount of storage available to meet that load would remain static. The RGS also allege that their ability to use storage to take advantage of seasonal hedging is lessened. RGS Ex. 1.0 at 20. Furthermore, since customers and suppliers pay for storage through base rates and PGA charges, the RGS contend that storage capacity should follow customers when they change suppliers. Accordingly, the RGS proposed the following language in their Rider AGG:

> In the event that Supplier's storage capacity level increases significantly in any given month due to changes in the supplier's customers annual volumes, Supplier may purchase from Peoples storage inventory gas at then current first of the month price index published in Inside F.E.R.C.'s Gas Market Report for Chicago City Gate to enable the supplier to meet its minimum storage inventory levels as set forth below. Corresponding, in the event that supplier's storage capacity level decreases significantly in any given month due to changes in the supplier's customers annual volumes, supplier may sell to Peoples storage inventory gas at then current first of the month price index published in Inside F.E.R.C.'s Gas Market Report for Chicago City Gate to enable the supplier not to exceed its maximum storage capacity level. In any case, upon reasonable notification, Peoples at its sole discretion may require a supplier to purchase or sell storage inventory gas under the same price guidelines as outlined in this paragraph to meet prescribed storage inventory levels as set forth below.

RGS Ex. 2.1

The RGS claim that the foregoing text "is consistent with Nicor's treatment of storage capacity when customer migration impacts a supplier's obligations." RGS Init. Br. at 20. Although this language appears in the RGS' proposed Rider AGG, the RGS says that it "would also work under the Company's current program." Id.

The Utilities acknowledge that they do not reallocate storage among CFY suppliers during the withdrawal season. They state that they have designed the CFY program so that "withdrawals occur in a measured way over the course of the winter with appropriate adjustments for weather." PGL-NS Ex. TZ-2.0 at 51. "[I]t would not be practical to allow adjustments to inventory because this could entail winter injections or purchases and sales of gas by the Utilities to adjust the inventory balance." Id.

Commission Conclusion

The Commission approves the RGS' request for reallocation of storage during the withdrawal season, though we will not adopt the RGS' proposed textual revisions for the Utilities Rider AGG. The concerns of the RGS are valid and a reasonable remedy is readily available, while the corresponding burden on the Utilities is minimal. When storage capacity follows the customer, the potential that a competitive provider will have insufficient storage, or, more likely, pay a penalty for excess use of storage, is obviated. The Commission is not inclined to discourage competitive switching by adding unnecessary risk to the cost structure of alternative suppliers. Moreover, customers should not forfeit storage capacity when switching suppliers during the withdrawal season. Conversely, the Utilities do not need to retain storage rights for customers they no longer serve.

The Utilities' aversion to withdrawal season gas purchases, when prices are likely to be higher, is understandable, but we do not assume that the Utilities will need to make significant withdrawal season purchases with the RGS proposal in effect. We find it likely that virtually all changes in a CFY supplier's volume will be associated with the movement of *existing* accounts among providers. The Utilities provide storage and balancing for both RGS customers and sales customers, so the overall quantity of gas to be stored and balanced should remain essentially constant, except for new customers, whom either the Utilities or CFY providers will need to serve. Nor will the Utilities have to develop new information systems to accommodate storage reallocation during withdrawal season. The Utilities already recalculate monthly storage allocations as CFY customers change suppliers during the injection season (PGL-NS Ex. TZ-2.0 at 51) so they have information and billing systems in place to process and allocate CFY-affiliated storage during the winter.

However, the Commission finds that RGS's proposed text, quoted above, does not reallocate storage to account for customer migration. Rather, it is entitled a "Storage Purchase in Place/Cash-Out" provision, by which a CFY supplier will have an option to purchase or sell storage gas at a predetermined price. Whatever merits this provision might have in another context, it does not reallocate storage capacity in response to customer migration, which is what the RGS request. Indeed, the provision would apparently not reallocate storage at all if customer migration did not "significantly" alter the CFY supplier's capacity.

On exceptions, however, the RGS defend their proposal as mechanism for transferring stored gas along with storage capacity, in order to more practicably supply fuel to migrating customers. RGS BOE at 30. Staff "does not oppose" such gas transfer, at market price, "when customers migrate between the [Utilities] and a marketer." Staff RBOE at 63. The Utilities oppose the RGS provision, calling it "complicated and convoluted." PGL-NS RBOE at 91. The Commission finds that the RGS' rationale for transferring gas along with storage capacity for migrating customers is reasonable, but RGS's proposed text does not address such transfer.

Accordingly, we will require the Utilities to perform the same storage reallocations during the withdrawal season that they perform during the injection season, as described by Utility witness Zack. This will minimize the changes required of the Utilities to accommodate customer migration to CFY suppliers. Additionally, any gas in storage for the migrating customers shall be transferred with the pertinent storage capacity, at the applicable price set forth the quoted text from RGS Ex. 2.1 above. Because that gas will already be aligned with the migrating customer's usage, the CFY supplier will not have to purchase additional gas during the heating season.

e) Month-End Delivery Tolerance

In the event their proposals for a revised Rider AGG and capacity release were rejected (as they are, above), the RGS request that their month-end gas delivery tolerance be expanded to 10% or, preferably, eliminated entirely, to provide greater flexibility. RGS Ex. 2.0 at 14. Deliveries within the tolerances are not subject to penalty, even though they exceed established limits. The Utilities presently allow a 2% month-end delivery tolerance, which they have proposed to expand to 5% in these proceedings[68]. PGL-NS Ex. TZ-1.0 at 29. The RGS argue that customers can be hesitant to use their full daily delivery allowance of 10% for fear of exceeding smaller monthly limits.

The Utilities acknowledge that CFY suppliers are allowed a 10% daily delivery balance, but insist that month-end tolerances should nevertheless remain smaller, to match the Utilities' overall operating plan. PGL-NS Ex. TZ-3.0 at 26. They maintain that their proposed increase of the month-end tolerance to 5% is sufficient and, accordingly, oppose the RGS' request for a 10% allowance. Staff also opposes the RGS' proposal, because it is "more difficult for the utility to plan its purchases as well as their storage injections and withdrawals if the monthly tolerance is too large which would result from adopting the RGS proposal." Staff Init. Br. at 260.

Commission Conclusion

The Commission concludes that the Utilities' proposed increase of the month-end delivery tolerance is an adequate response to the RGS' request for greater flexibility. The RGS have not rebutted the contentions of the Utilities and Staff that the Utilities themselves have month-end obligations and that an expanded tolerance for CFY suppliers would make fulfillment of those obligations more burdensome.

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[68] That is, the current month-end delivery tolerance "in the current Rider AGG is plus or minus 2% of the sum of the Required Daily Delivery Quantities ('RDDQs') for each day during the month. The RDDQ is the Company's estimate of the usage of pools of customers served by CFY suppliers." RGS Init. Br. at 20.

f) Working Capital Related to System Gas Costs/Monthly Customer Aggregation Charge

Since CFY suppliers incur working capital costs associated with gas stored on behalf of their customers, they aver that "it would be inappropriate to allocate the Company's working capital costs to CFY customers because they do not purchase or consume" Utility-supplied gas. RGS Init. Br. at 22. The Utilities agree and "propose to include a credit from working capital in the CFY customer Aggregation Charge." NS-PGL Init. Br. at 211. The resulting credit is $1.48 per North Shore customer and $2.26 per Peoples Gas customer. PGL-NS Ex. 3.0 at 31. The North Shore credit leaves a three-cent per customer per month aggregation charge, and the Peoples Gas credit effectively eliminates Peoples Gas's aggregation charge and leaves an $0.83 per customer per month credit. The RGS propose that the credit be applied to the ABGC, which the RGS describe as "competitively neutral" because of the way CFY suppliers incur and recover gas storage-related working capital costs on their customers' behalf. RGS Rep. Br. at 14. Moreover, "an offset to the ABGC would allow customers to more easily compare the costs of participating in CFY and sales service." Id.

Peoples Gas prefers that the remaining credit "simply become a credit on the bill." PGL-NS Ex. 3.0 at 31. Peoples Gas opposes applying the credit to the ABGC, "because the ABGC is a gas cost and the credit relates to base rate costs." Id. Further, the Utilities argue, "[a]pplying the credit to the ABGC would affect the gas cost reconciliation with revenues that are not recoverable gas costs. Also, the credit is a per customer credit while the ABGC is a per therm charge and it is unclear how the per customer credit would be integrated into the per therm ABGC." PGL-NS Rep. Br. at 163-64.

Commission Conclusion

The Commission approves the parties' agreement to reduce the customer Aggregation Charge in the amounts described above. We reject the RGS' proposal for applying any excess credit against the ABGC. The Utilities are correct that the proposal is not sufficiently developed on the record, so that the credit can be accommodated in the per-therm ABGC. The RGS tacitly acknowledge this, as reflected in their subjunctive recommendation "that the credit apply to the ABGC *or in a competitively neutral manner* such that the credit offsets a CFY customer's supply portion of the bill and not the delivery portion of the bill." RGS Rep. Br. at 14 (emphasis added).

It is implicit in this discussion that the monthly aggregation charge is not formally being eliminated, although that is the practical outcome of the working capital credit applied against the aggregation charge. The RGS did not address elimination in their reply brief, and we cannot say, on the record as it stands, that the costs identified by the Utilities (PGL-NS Init. Br. at 212) should not be recovered (even though offset) through the Aggregation Charge.

2. Customer Enrollment

a) Customer Data Issues

The Utilities maintain that they have made four proposals regarding customer data that satisfactorily address concerns raised by CFY suppliers. First, they propose to provide customers lists, excluding customers on the Utilities' "do not contact" lists, to CFY suppliers without customer consent but pursuant to a contract with the Utilities. The customer list would include customer names and addresses, and whether the customer is in service classification 1N or 1H, but it would not include customer telephone numbers. The Utilities will not do this more than once every six months. The RGS and NAE accept this limitation. RGS Ex. 2.0 at 15; NAE Rep. Br. at 3.

Second, the Utilities have proposed to provide, pursuant to a contract, more detailed customer information to CFY suppliers in two tiers. Tier 1 would not include any customer information and would not require customer consent. Tier 2 would include customer information but would require customer consent. Tier 2 information would include name, billing address, premises address, usage, type of meter reading and other reading dates. Neither tier would be provided to CFY suppliers for free.

If directed to do so by the Commission in these proceedings, the Utilities would, third, provide a customer's payment history to a CFY supplier, if the supplier, among other things, warrants that it has that customer's consent to obtain that customer's payment history and indemnifies the Utilities against any claim that the supplier does not have such consent; and, fourth, the Utilities would provide a customer's past due amounts to a CFY supplier if the supplier complies with the same consent and indemnity requirements.

Commission Conclusion

As a general proposition, the Commission will require the Utilities to supply the information described in the four categories above, thereby providing the mandate the Utilities apparently seek[69]. That said, RGS and NAE raise several specific issues concerning the manner in which the pertinent data would be furnished. Consequently, the general approval announced in this paragraph is modified by, and subject to, the specific conclusions articulated in the subsections of this Order below.

Also, the Utilities and NAE appear to disagree about the inclusion of phone numbers among the data that must be disclosed. The Commission is not inclined to abet telemarketing and will not require disclosure of phone numbers. Alternative providers can use mailings to attract inbound calls and email communication.

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[69] On exceptions, Staff objects to the provision of customer lists without customer consent, reminding us that we rejected such non-consensual disclosure in Nicor. Staff BOE at 88-89. The Commission is willing to mandate a different result in these proceedings, however, because NAE has presented a more persuasive case concerning the public nature of names and addresses and the additional cost of procuring such information from commercial sources, with potentially inferior accuracy. We certainly share Staff's privacy concerns, and we have endeavored to protect customer privacy without diluting the customer benefits associated with expanded and sustainable choices among gas providers.

Similarly, NAE disagrees with Staff (Staff Init. Br. at 261) and the Utilities (PGL-NS Init. Br. at 214) about prohibiting CFY suppliers from using customer information obtained from the Utilities for any "non-utility service" or "for any purpose other than in connection with gas service." The Commission believes that such a prohibition is appropriate, however. Our function is to oversee public utility services, not to promote non-utility marketing schemes or customer data sales, especially when we required transmission of certain customer data without charge (see below). Consequently, Utility contracts for information transfers should bar re-transfer of the data furnished for purposes other than provision of gas service. However, we do not, and cannot, preclude alternative providers from obtaining information directly from customers or other sources. Any limits on the re-transfer of information provided directly by customers and other sources would be determined by the information provider and the CFY supplier.

i.) Timing of Data Transmission

The RGS assert that customer data is needed before a CFY supplier agrees to furnish service, so that the supplier can check the customer's creditworthiness. RGS Rep. Br. at 15. Consequently, the RGS want the Utilities to furnish data as soon as proof of customer consent is obtained and presented. Id. Vanguard takes the same position. Vanguard Init. Br. at 9-10. So, too, does NAE, who adds that pre-enrollment receipt of customer data facilitates the single-billing option, i.e., direct and unitary billing by the alternative supplier, because customers in arrears to a utility cannot be single-billed. NAE Init. Br. at 5.

We conclude that customer data should be provided to the alternative gas supplier as soon as is practicable after the supplier presents valid customer consent to the Utilities. The Utilities cannot insist that the customer be "active and flowing" or even committed to receiving service from the alternative supplier. The pertinent customer information is of its greatest use to the supplier before that commitment has been made, to assess creditworthiness.

ii.) Data Fees

The RGS purport in their initial brief that the Utilities are willing to supply customer data without cost. RGS Init. Br. at 23. The Utilities deny this, albeit without supporting argument[70]. PGL-NS Rep. Br. at 164. Consequently, we will treat this as a disputed issue. NAE avers that the Utilities already keep the Tier I and Tier II customer data "for their own use, and the costs of maintaining that information is recovered from sales and transportation customers through the Utilities' rates [*citing* Tr. at 633 (Zack)]. The Companies should not be permitted to double-recover those costs by charging suppliers for access to that information." NAE Rep. Br. at 6. Second, NAE stresses that the pertinent data are "ultimately the *customer's* data." Id. (emphasis in original). Third, the fees imposed on CFY customers and suppliers "subsidize the administration

[70] In fact, we cannot be certain that the Utilities object to providing customer lists without charge. Their reply brief only discusses Tiers 1 and 2 data.

and maintenance costs of that program, which should include mechanisms for allowing customers to provide their data to suppliers." Id.

The Commission will not allow the Utilities to impose a charge for furnishing either customer lists or Tier 1 data. The Utilities are not commercial data supply entities. Customers have willingly submitted the pertinent data to them in their capacity as monopoly providers of gas delivery service, operating under certificates of public convenience and necessity. At the same time, the Utilities compete with CFY providers to supply gas. Although gas supply is performed without markup, sole access to the customer, as a bundled provider, has value for, among other things, bill inserts and cross-promotions. Moreover, as NAE points out, the Utilities receive compensation for maintaining customer data though base rates. We doubt that the trivial cost of electronically transmitting that information to CFY suppliers would exceed rate elements collected by the Utilities. Therefore, we conclude that the basic data in customer lists and Tier 1 should be furnished without charge. However, the Utilities can insist on providing the data pursuant to a contract with the alternative supplier, setting out terms and conditions, as described in NAE Cross-Ex. 2.0 (Zack). Also, if the supplier wants data in other than electronic form, the Utilities may impose a charge.

Tier 2 data, payment history, and arrearage data are a different matter. As we determine below, these data categories will involve customer consent. Consequently, the Utilities will have to do more than electronically transfer information they have already gathered with existing information system configurations. They will also have to receive and monitor customer consent information. The Utilities can require compensation for that service.

As recommended by NAE (NAE BOE at 4) and supported by Staff (Staff RBOE at 64) we direct the Utilities to file a tariff describing in sufficient detail how customer consent will be monitored by the Utilities and how Tier 2 data will be transmitted to the requesting entity. The tariff should be accompanied by supporting cost data justifying all included charges. No duplication of cost recovery accomplished through any other Utility tariffs should occur[71].

b) Evidence of Customer Consent

There is consensus among the parties that customer consent should be a prerequisite for obtaining customer payment and arrearage information. There is no consensus regarding the mechanisms for accomplishing this. Staff cautions that the customer must "explicitly authorize[] in clear, non-technical terms, the marketer to have this information." Staff Init. Br. at 262. For their part, the Utilities want the Commission's unambiguous imprimatur for a customer consent mechanism, so that they are not caught up in disputes regarding the legitimacy on consent. PGL-NS Rep. Br. at 165. In particular, they seek indemnity from damage claims. They also raise

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[71] That said, we will not specifically prescribe how the Utilities should avoid cost recovery duplication, as NAE proposes ("providing tariff reductions to existing CFY riders to the extent that the monitoring costs are duplicative," NAE BOE at 4). The Utilities may be able to draft a Tier 2 information tariff that, by itself, avoids duplicate recovery.

additional issues regarding third-party verification of consent and Utility access to CFY supplier form contracts. PGL-NS Init. Br. at 214.

The RGS propose language drawn from one of their members, supported by general comments about the appropriate parameters of customer consent. RGS Init. Br. at 25. But the RGS then appear to endorse "the Nicor process." RGS Rep. Br. at 17. NAE initially proposes certain language (NAE Init. Br. at 10) which it later describes as "consistent with" Nicor tariff sheets attached to its Reply Brief. NAE Rep. Br. at 8. The tariff sheets are far more detailed, and it is not clear to the Commission whether NAE is recommending only the limited text in its Initial Brief or the more comprehensive text attached to the Reply Brief.

Commission Conclusion

As the Commission perceives it, the parties have submitted a hodge-podge of partial recommendations, generic concurrences and broad principles, apparently expecting us to sort things out for them. We are not inclined to do so. Customer consent involves important and potentially conflicting issues of consumer privacy and autonomy, which require careful and comprehensive drafting to ensure genuine consent and avert disputes among stakeholders. Assuming solely for the sake of argument that a rate-setting proceeding is the appropriate context for reviewing the requisite procedures and written agreements essential to customer consent, it is incumbent upon the interested parties – particularly those who want access to information – to provide clear, comprehensive and detailed recommendations. Given the sheer volume of issues and evidence to address in these rate cases, the Commission will not accept the burden of drafting contracts, any word of which can elicit further disputes.

Accordingly, we will simply adopt principles that must be embodied in the requisite customer consent process. The Utilities can consult with other stakeholders to arrive at consensus terms and conditions incorporating those principles, or they can simply incorporate the principles in their proposed customer consent provisions. First, as the Utilities request, they should not be responsible if there is any dispute between a CFY supplier and its customer about the scope or effectiveness of a customer's authorization to the CFY supplier to obtain payment history or past due payment data from a Utility. Second, the CFY supplier shall indemnify the Utilities against any customer damage claim if the CFY supplier receiving the data does not have the requisite authorization, or if the customer revokes the authority prior to the occurrence of a purportedly damaging error or omission. Third, customer consent must be unequivocal and all matters to which the customer consents must be stated in unambiguous and everyday language. Fourth, a customer's written signature is unnecessary as proof of consent, so long as other satisfactory indicia of consent are provided. Fifth, third-party verification of customer consent is not required.

The Commission rejects NAE's request (NAE BOE at 4-5) that the Utilities be required to supply customer payment and arrearage information before provisions regarding evidence of customer consent are in place. We do not want to open a temporary window of opportunity for the very non-consensual disclosure we intend to preclude. However, so that there is no foot-dragging in the process of establishing consent procedures, the Commission directs that the Utilities have customer consent processes in place and operational no less than 45 days after entry of this final Order[72].

c) Minimum Stay Requirement

The Utilities initially proposed to continue requiring a CFY customer returning to Utility sales service and not selecting another CFY supplier within 60 days to remain on Utility sales service for a minimum of one year before being again eligible to switch to CFY service. PGL-NS Ex. TZ-2.0 at 57. Subsequently, the Utilities modified their proposal to require retention of a customer that does not select another CFY supplier within 90 days. PGL-NS Ex. TZ-3.0 at 33. The Utilities offer three reasons for this requirement. First, they assert that it provides reasonable certainty to their gas supply planning. Second, they argue that it prevents customers from switching back and forth between CFY suppliers and the Utilities to take advantage of temporary price fluctuations. Third, they point out that it is not substantively different from the minimum terms provisions that CFY suppliers insert in their own contracts.

The RGS respond that a minimum stay requirement is anticompetitive and limits customer choice. RGS Init. Br. at 26. They challenge the Utilities' supporting rationales, stating that the movement of individual residential customers will not upset the Utilities' supply planning for approximately one-million customers. The RGS also contend that individual residential customers cannot exploit arbitrage opportunities, given the lag in the switching process. Id. The RGS recommend that customers be allowed two switches per year, with no minimum stay requirement. If that proposal is rejected, the RGS requests that the time a customer has to switch after returning to Utility sales service be extended days to 120 days before the one-year minimum stay requirement is applied. RGS Ex. 2.0 at 27.

Commission Conclusion

We agree with RGS that the arbitrage potential for residential and small commercial customers is minimal, and that overall system supply is not meaningfully affected by switching by such customers. The more substantial concern is that the resources of both the CFY suppliers and the Utilities could be wasted processing switches by customers temporarily enticed by marketing strategies. The RGS clearly understand this, since they impose their own one-year contracts and exit fees to discourage frequent switching. RGS Init. Br. at 27. In order to balance that concern with the benefits of customer freedom, the Commission approves the RGS's compromise proposal to allow switches away from the Utilities within 120 days before the one-year minimum may be imposed.

3. Rider SBO

a) Billing Credit

NAE proposed that the Utilities provide CFY suppliers a credit for single billing under Rider SBO (Single Billing Option), to reflect costs avoided by the Utilities when

[72] This deadline shall apply without exception - irrespective of the filing of an appeal of this Order by any party and irrespective of the progress of any attempt at consensus among the stakeholders.

they do not have to issue a bill for their distribution charges. NAE Ex. 1.0 at 7-12. The Utilities initially opposed any credit, but later agreed to provide a 33-cent per customer monthly credit for CFY suppliers billing under Rider SBO. PGL-NS Ex. TZ-3.0 at 31. The proposed credit reflects the Utilities' estimate of postage and paper costs. Tr. at 624 (Zack).

However, NAE maintains that there are additional billing costs (e.g., quality control and information technology) not removed by the Utilities' proposed credit. The parties agree that there is insufficient information available to accurately quantify such costs. NAE therefore recommends that the Utilities perform an embedded cost study to identify all billing costs. NAE notes that we have required such studies in previous proceedings. As a secondary alternative, NAE requests an avoided cost study. Staff supports a cost study. Staff Rep. Br. at 110.

The Utilities object to performing either study. They stress that no supplier is actually using the single billing option. They caution that a study might uncover additional costs that could even reduce the 33-cent credit.

Commission Conclusion

The Commission's policy is to align costs with charges and, in general, we prefer that comprehensive information be available for rate-making. Accordingly, we direct the Utilities to conduct an avoided cost study (which we understand to be the less burdensome alternative) regarding their billing costs. The Utilities may, at their discretion, perform an embedded cost study instead, should they believe it might identify costs to be added to Rider SBO. In either case, the study results should be provided to the Commission in 120 days, and Rider SBO should then be revised as necessary to reflect those results. For now, the 33-cent credit should be included in Rider SBO.

b) Order of Payments

When a customer receiving gas from an alternative supplier and distribution service from one of the Utilities makes partial bill payment, the funds are allocated between the supplier and the Utility. Until now, the allocation, or "order of payments" has been different under Rider SBO, where the supplier bills and collects all charges, than under the Utilities' single bill, where the Utility bills and collects all charges. Under Rider SBO, the Utilities get all their charges paid before the CFY supplier receives any payment. In contrast, under the Utility (LDC) single billing option, the order of payment is Utility past due charges, then CFY supplier past due charges, then Utility current charges, then CFY supplier current charges.

NAE, supported by the RGS, requests that the order of payments under the Utility single billing option be used for SBO as well. The Utilities recommend the reverse – that the SBO order of payments, by which all funds go first to Utility charges (current and past due) should be incorporated in the LDC option. In short, in single-billing situations, CFY suppliers request greater sharing of partial payments and the Utilities request none (unless the partial payment exceeds all Utility charges).

The CFY suppliers argue that the Utilities' proposition disadvantages them absolutely by increasing their risk of non-collection, and relatively, by reducing the Utilities' risk. The Utilities counter that the Rider SBO order of payments was approved in Docket Nos. 01-0469 and 01-0470, while the Commission has never addressed the order of payments under the LDC billing option.

Commission Conclusion

As the Commission views it, the Utilities' intention is to reduce their own collection risk by shifting it to the alternative gas suppliers. The likely result is an incrementally adverse impact on supply competition, as the competitors either absorb collection losses or adjust rates upward. That would be inconsistent with our policy of expanding customer choice, without alleviating any problem indentified by the Utilities – who designed the LDC payment order themselves and ascribe no difficulties to it. As for our actions in Docket Nos. 01-0469 and 01-0470, we were not presented with the issues or choices framed in the present dockets. The Commission now has the opportunity to refine our approach to payment allocation. We conclude that the order of payments in the Utilities' LDC single-billing option should also apply under Rider SBO.

c) NSF Checks

Under the Utilities' existing practice regarding the return of customer non-sufficient funds ("NSF") checks, when one of the Utilities issues a single bill and receives a customer check, the Utility credits the appropriate funds to the CFY supplier, and if the check is later determined to be NSF, the Utilities do not try to recover the uncollected funds from the CFY supplier. Correspondingly, if a CFY supplier billing under Rider SBO were to receive a check, the supplier would pay the appropriate funds to the relevant Utility, and if the check were later determined to be NSF, then the Utility would not return any portion of the funds to the CFY supplier that accepted the NSF check for payment. NAE contends that this arrangement favors LDC single billing and discourages the use of SBO.

NAE wants to alter the foregoing practice so that when either party – supplier or Utility - determines that a check is NSF, it will receive reimbursement from the other party, to whom it has already transferred funds. Thus, instead of the suppliers and the Utilities each bearing the burden of their own customers' bad checks, they would share that burden, in that each would remain unpaid (unless or until the customer pays the arrearage later).

Commission Conclusion

The issue is whether to promote provider responsibility or debt sharing. We will resolve that issue by rejecting NAE's proposal. Whether the pertinent customer is single-billed by the supplier or the Utility, that customer will be the supplier's customer, in the sense that the supplier will have marketed the customer and vetted the customer's creditworthiness. The Utilities' role will only include the provision of tariffed services (distribution, and perhaps billing) to facilitate fulfillment of the supplier's agreement with the customer. The Commission sees no convincing reason why the Utilities should share bad debt risk when they have an obligation to provide service and no control over customer selection.

4. Purchase of CFY Supplier Receivables

The RGS propose a Purchase of Receivables ("POR") program, under which the Utilities, upon request by a CFY supplier, would purchase the supplier's accounts receivable associated with natural gas supply. In other words, the Utilities would assume responsibility for collecting whatever is owed for gas service by the CFY supplier's customers, with any shortfall borne by the Utilities.

The RGS assert that the Utilities would be "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 supplier and is subject to a periodic reconciliation process; or 2) an element of the utility's base rates." RGS Rep. Br. at 19. That is, under the first option, the Utilities would remit to CFY suppliers something less than the face amount of the suppliers' receivables, then hope that the difference (i.e., the discount) equaled or exceeded permanently uncollectible debt. However, the RGS prefer that no discount be included in their proposed POR regime. The Utilities would simply pay face value for receivable accounts. Under the second option, the Utilities would increase their uncollectible expense to account for the additional bad debt assumed from CFY suppliers.

The RGS argue that their proposal would remedy several inequities they perceive. They stress that, at present, customers cannot be disconnected for non-payment of an alternative supplier's gas charges, which undermines the suppliers' collection leverage. If receivables were assumed by the Utilities, the RGS believe disconnection would be permissible because the pertinent arrearages would be owed to the Utility involved. They further assert that CFY customers currently "pay twice for debt collection efforts" because both the supplier and the Utility have debt collection costs built into their rates. RGS Init. Br. at 31. They also contend that a POR regime would increase overall efficiency, by eliminating any need for separate credit inquiries and collection efforts by the CFY supplier and the Utilities.

The RGS additionally emphasize that POR programs are in place in other jurisdictions, involving both gas and electric utilities. Id. at 36. Moreover, the RGS point out, a bill passed by the General Assembly and signed by the Governor in November 2007, Public Act 095-0700 ("PA 0700"), expressly requires ComEd and the Ameren Companies to offer a POR program in connection with electricity services. Id. at 37; RGS BOE at 24.

The Utilities rejoin that the RGS' proposal "is an inappropriate attempt to shift business risks from CFY suppliers to the Utilities and utility customers." PGL-NS Init. Br. at 219. Additionally, they underscore that PA 0700 does not apply to gas utilities and expressly requires "`a just and reasonable discount rate to be reviewed and approved by the Commission after notice and hearing. The discount rate shall be based on the electric utility's historical bad debt and any reasonable start-up costs and administrative costs associated with the electric utility's purchase of receivables.'" PGL-NS Init. Br. at 221 (*quoting* PA 0700). In the Utilities' view, "[t]here are no facts in the evidentiary record upon which the Commission could determine an appropriate discount rate." Id. Similarly, the Utilities charge, if the Commission were instead inclined to adjust the Utilities' revenue requirements to reflect a POR, "there is no data in the record that would come close to providing a basis for calculating how much the Utilities' revenue requirements would need to be increased to offset the shift of risks, burdens, and expenses." Id. at 220.

Staff also opposes the RGS's POR proposal, stating that it may make the Utilities' business "more risky if the POR induces marketers to target customers that are at a high risk of default." Staff Init. Br. at 264.

Commission Conclusion

The Commission rejects the RGS' POR proposal. The RGS endeavor to frame the dispute arising from their proposal as a supplier-versus-utility match-up, as if customers were unaffected third parties. In fact, irrespective of the compensatory mechanism selected, whether the RGS' preferred "zero discount," an actual discount, or an adjustment to the Utilities' revenue requirement, ultimate responsibility for CFY bad debt will shift to the Utilities' *customers*, including sales customers. The RGS understand this. "Under a zero percent discount POR program, the [Utility] recovers uncollectible and any start-up and administrative expenses from CFY customers and sales customers through base rates." RGS Rep. Br. at 25-26. The POR proposal thus shifts both the risk of CFY bad debt and CFY bad debt itself to all ratepayers, including those with no relationship with the CFY suppliers.

This shifting of responsibility is exacerbated by the discretion the POR program would confer on suppliers to avoid credit assessments before signing up customers. "It would no longer be necessary for CFY suppliers to examine customer payment histories or perform credit checks on potential customers because, under POR, CFY suppliers would be guaranteed of all their customers' receivables at a discounted rate [although, as already noted, the RGS offer no discount]." RGS Init. Br. at 33. The RGS view these circumstances as desirable, because they "bring[] choice to customers where it was previously unavailable." Id. The RGS is apparently referring to customers with unsavory credit histories--including, RGS acknowledges, customers with repeated arrearages for gas service. Tr. at 1025-26 (Crist). Such customers would indeed enjoy broad choice under the RGS' zero discount POR, since neither they nor the CFY supplier would have any stake in their accountability[73].

The General Assembly did not mandate POR for gas suppliers when it enacted PA 0700 for electricity suppliers. Although the Commission could infer from that omission that the General Assembly intentionally elected to treat the gas and electricity markets differently, the RGS claim that new legislation was required for electricity because of limitations imposed by subsection 16-103(c) of the Act, while no comparable

[73] In contrast, when there is a meaningful discount, the alternative supplier at least retains an interest in *monitoring* bad debt, so that it does not surrender its receivables too cheaply.

statute constrains our authority to order gas utilities to provide POR. RGS BOE at 25. However, subsection 16-103(e) only bars this Commission from requiring an electric utility to provide certain "tariffed services." Under Section 16-102 of the Act, "tariffed services" are defined as services for *retail customers*. In contrast, PA-0700 contemplates a POR tariff for "*retail electric suppliers*." (Emphasis added.) Accordingly, the RGS' statutory analysis does nothing to clarify the General Assembly's intentions or our own authority, absent specific legislation, to mandate POR[74].

In any event, the Commission concurs with the Utilities that the evidentiary record is insufficient to establish either an appropriate discount or an increased revenue requirement associated with a POR tariff. By comparison, PA 0700 contemplates a hearing before a discount rate can be set for an electric utility. As we understand that requirement, a detailed rate mechanism, supported by quantitative evidence, would be assessed. Here, there is only a concept, with no discount rate above zero even proposed, much less supported with evidence. Similarly, there is no quantitative evidence to sustain a revenue requirement adjustment. In a proceeding in which, by comparison, NAE requests a billing cost study, it would be inconceivable to alter revenue requirement without quantitative analysis.

5. PEGASysTM and Customer Information

PEGASys is the electronic bulletin board through which the Company conducts daily transactions with CFY suppliers. All parties, including the Utilities, agree that PEGASys needs improvement. The Utilities have already completed certain modifications and more are in progress. PGL-NS Init. Br. at 221-22. However, the Utilities envision completion of their improvements "no later than August 2008…and perhaps as early as June 2008." Id. at 222. The RGS and NAE both request an earlier completion date, suggesting 30 days after entry of this Order (that is, the first week of March 2008).

Commission Conclusion

The Commission certainly understands the interest of the RGS and NAE. PEGASys is a critical interface by which they conduct important elements of their business. To facilitate that business, the Commission would be inclined to establish an earlier deadline for the ongoing improvement, if we had a more granular evidentiary basis for doing so. The record does not indicate what specific work is under way or whether its pace can be accelerated. Nor is there evidence that the Utilities are stalling. We are reluctant to require faster action without knowing if that is reasonable.

We infer from Utilities' own declarations that the PEGASys improvements can be finished and operational by August 2008. Therefore, we will hold the Utilities to that projection. The enhancements described in the Utilities' testimony must be in place and functioning appropriately by August 15, 2008.

[74] Since we are rejecting POR for the specific reasons discussed in this Order, which do *not* include the absence of administrative authority to mandate POR for gas utilities without specific legislative authorization, the Commission does not need to – and does not – decide whether such legislative authorization is necessary.

E. Tariff Corrections and Clarifications

The Utilities have proposed five corrections and clarifications to their proposed transportation tariffs. Each is listed below. No party has objected to any of them. The Utilities also proposed three clarifications to their Terms and Conditions of Service. No party has objected to any of them. The Commission finds them reasonable, and they are approved.

1. Rider SST, Section F

The Utilities propose to add the following sentence to the end of the last paragraph in Section F: "For quantities that would be in excess of this limitation, the customer shall purchase gas under the Companion Classification in a quantity not to exceed the product of the SSQ times the number of days in the month minus standby service gas purchased during the month and any remaining quantity shall be Unauthorized Use."

2. Rider TB, Section A (Peoples Gas Only)

Peoples Gas proposes to add in Rider TB, Section A, Imbalance Coincidence Factor, a new sentence before the last sentence of the definition: "For purposes of determining the ICF, the Company shall use only Service Classification No. 4 customers' data."

3. Rider LST-T (Peoples Gas Only)

Peoples Gas proposes to delete the charge from Section B of Rider LST-T and add the non-charge language to Section J of Rider LST-T.

4. Rider SST, Section H

A proposed change to Rider SST, Section H, was made moot by the Utilities' proposed changes to Rider SST in their surrebuttal testimony.

5. Rider SST, Section K

Rider SST, Section K, addresses customers who do not yet have daily metering installed. There is a minimum AB requirement and a gas purchase obligation if the minimum AB is not met. The Utilities propose that the purchase price be 110% of the AMIP.

6. Rider TB, Section H and Rider P, Section G

The Utilities propose that the following be added to the second paragraph of Section H: "or increase the amount of the imbalance." A comparable change in Rider P, Section G, would be appropriate.

7. Terms and Conditions of Service

These matters are addressed in Section IX.D.8. of this Order.

XI. UNION PROPOSALS

Local Union No. 18007, Utility Workers Union of America, AFL-CIO (the "Local"), entered this proceeding as a representative of workers employed byPeoples Gas, but not by North Shore. According to the Local: Peoples Gas "is not currently meeting its obligations to acquire, train, and maintain an adequate workforce. As a result…[Peoples Gas's] current complement of on-staff resources is unable to handle its normal workload." Local Init. Br. at 2. These conditions, the Local alleges, limitPeoples Gas's ability to provide "safe, reliable and cost-effective gas service." Id. at 3. Therefore, the Local requests that the Commission take two actions: 1) direct Peoples Gas to adopt the Local's "One-For-One" workforce replenishment plan (the "Plan"), under which Peoples Gas will have to fill higher-skilled job vacancies with a qualified Local candidate, unless job obsolescence or infrastructure improvements dictate otherwise; and 2) require an independent audit of (a) work order response times and backlogs (inclusive of temporary repairs) at PGL, and (b) staffing levels among the utility workforce at PGL. Local Init. Br. at 5. PGL opposes both of the Local's requests.

A. One-for-One Replenishment Plan

The stated objective of the Plan is to preclude Peoples Gas from leaving senior positions unfilled (absent job obsolescence or overriding infrastructure improvements). Thus, Peoples Gas "would commit to replenishing any union vacancy with an internal Local… candidate." UWUA Ex. 1.0 at 8. More specifically, "[e]ach May 1, for example, Peoples Gas can release to [the] Local…a report that provides attrition figures by department and job classification. [Peoples Gas] could commit to routinely replenish vacant posts in a predictable cycle: with internal candidates (selected according to a set of pre-approved metrics, *i.e*., experience with [Peoples Gas's] operations and a supervisor's performance approval) on a set clock after a prescribed period of time has elapsed from release of the attrition report (*e.g.,* 90 days)". Id. at 19.

1. Scope of Commission Authority

As a threshold issue, Peoples Gas questions the Commission's authority to mandate the Local's plan for PGL's operations. Peoples Gas and the Local have a collective bargaining agreement ("CBA"), which is not under the Commission's purview. According to Peoples Gas, problems arising under the CBA would either be governed by the CBA's own grievance procedure or would be addressed under federal jurisdiction. Peoples Gas cites 29 U.S.C. § 160(k) (the National Labor Relations Board ("NLRB") has primary jurisdiction over disputes arising out of allegations of unfair labor practices); San Diego Bldg. Trades Council v. Garmon, 359 U.S. 236, 245 (1959); *see also* Marquez v. Screen Actors Guild, 525 U.S. 33, 49 (1998) (labor disputes fall within the primary jurisdiction of the NLRB in part to promote a uniform interpretation of the NLRA). Suits alleging violation of a CBA can also be brought in any U.S. district court with jurisdiction over the parties. 29 U.S.C. § 185(a). To address the Local proposal, PGL stresses, the Commission would need to decide CBA issues, *see* Tr. at 821 (Gennett); if we approve the proposal, the Local would "achieve through a Commission order what it has not been able to bring about through negotiation." PGL-NS Init. Br. at 228.

The Local objects to the Utilities' characterization of the Local's proposals as "labor relations" matters that should be addressed through CBA negotiations and grievance procedures, or through dispute resolution proceedings before a federal court or agency. Instead, the Local argues, its proposals lie squarely within the Commission's statutory power to ensure that utility operations promote employee and public health and safety. The Local relies upon Section 8-505 of the Act[75], which states:

> The Commission shall have power, after a hearing or without a hearing as provided in this Section…to require every public utility to maintain and operate its plant, equipment or other property in such manner as to promote and safeguard the health and safety of its employees, customers, and the public, and to this end to prescribe, among other things, the installation, use, maintenance and operation of appropriate safety or other devices or appliances, to establish uniform or other standards of equipment, and to require the performance of any other act which the health or safety of its employees, customers or the public may demand.

The Local asserts that the foregoing text authorizes the Commission to impose the Plan because "the failure to fill open vacancies among top-tier employees is preventing the timely implementation of permanent repairs of gas leaks, thereby leaving employees and the consuming public at risk." Local Rep. Br. at 6.

The Local also points to our authority in rate-making proceedings, derived from Section 9-201(c) of the Act[76], to "establish the…practices, rules or regulations proposed, in whole or in part, or others in lieu thereof, which it shall find to be just and reasonable." The Local believes that Section 9-201(c) empowers us to prescribe staffing and repair practices as conditions coincident to rate revision. The Local additionally cites Section 8-401 of the Act[77], which declares that "[e]very public utility subject to this Act shall provide service and facilities which are in all respects adequate, efficient, reliable and environmentally safe."

2. Commission Conclusion re: Scope of Authority

Peoples Gas is correct that we do not oversee collective bargaining or enforce the Peoples Gas-Local CBA or resolve disputes under the CBA's provisions. Peoples Gas is also correct that allegations concerning "unfair labor practices" are within the province of the NLRB or comparable state agencies that oversee labor-management. However, the Local is not requesting enforcement of the CBA or alleging an unfair labor practice. Rather, the Local seeks enforcement of the public and employee health and safety provisions of the Act[78].

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[75] 220 ILCS 5/8-505.
[76] 220 ILCS 5/9-201(c).
[77] 220 ILCS 5/4-401.
[78] We note that the Local might also have cited Section 8-101 of the Act, 220 ILCS 5/8-101, which states, in pertinent part: "[e]very public utility shall furnish, provide and maintain such service instrumentalities, equipment and facilities as shall promote the safety, health, comfort and convenience of its patrons, employees and public."

The critical question, therefore, is whether the Commission has authority, when enforcing those health and safety provisions, to touch upon matters that might also be reasonably characterized as labor-management relations matters. We conclude that we have the requisite authority. To hold otherwise would be to end the regulation of public utilities. Every act of a public utility is performed by *someone*, and in countless instances that person is managed by another *someone*. While it is certain that the Commission's power to regulate the relationship between and conduct of those persons in not unlimited, it is equally certain that we can exercise some degree of control over those relationships and conduct, in order to fulfill our unambiguous mandate to require public utilities to promote the health and safety of employees and customers. The existence of a CBA does not deprive us of that authority. Indeed, the opposite is true. The signatories to a CBA simply cannot, with any expectation of impunity, agree to do what the law prohibits[79].

Illinois precedent on this point is not recent, but that is because the applicable law is clear and settled. The General Assembly has given the Commission general authority over public utilities and – at multiple places in the Act – the specific authority to ensure the health and safety of utility employees and customers. That authority was upheld by the Illinois Supreme Court in <u>Brotherhood of Railway Trainmen v Elgin, Joliet & Eastern Railway Co</u>, 382 Ill. 5, 46 N.E.2d 932 (1943) (Commission order specifying the manner in which drinking water should be provided for railroad employees was permissible under the predecessor statute to Section 8-505[80] and other portions of the Act, which "expressly authorize regulations for the safety of employees" <u>id</u>., 382 Ill. at 69, 46 N.E.2d at 939; and the Commission's authority to enter that order was not impliedly repealed by other state law addressing employee health and safety).

Accordingly - and without deciding, at this juncture, the exact contours of the relief we can or would require - the Commission concludes that we are authorized by the Act to regulate utility staffing and repair practices that are proven to impact the health and safety of public utility employees and customers.

3. Merits of the Plan

In support of the Plan, which would obligate Peoples Gas to promote Local members into higher-level employee positions[81], the Local asserts that Peoples Gas:

> …is facing current and anticipated shortages in its most highly-skilled employee positions…due in part to a long-term failure to promote employees up the ladder to positions of higher responsibility…[Peoples Gas's] unwillingness to promote employees to "top-tier" positions (unless required to do so in order to obtain regulatory relief) has led to lengthening delays in the permanent repair of temporarily-fixed gas leaks, which may not be safe until a "permanent" repair is made. While [Peoples Gas's] field

[79] As a relevant but extreme example, management and labor could not agree to create a hazardous condition.
[80] Then, Section 57 of the Act.
[81] In particular, "Crew Leader" (top position in Peoples Gas's Distribution Department), and "Senior Service Specialist No. 1" (top position in Peoples Gas's Service Department).

> service manual urges that temporary repairs be avoided or, if used, be followed promptly by a permanent repair…lag times to complete permanent repairs are expanding, and…the use of temporary repairs is increasing. Based on experience in the field… the reason for the lengthening lag is a shortage in the ranks of those highly-skilled employees without whom permanent repairs cannot be conducted. [Peoples Gas] has no basis for challenging these assertions, as it admitted…that it has no data on the use or duration of temporary repairs.

Local Init. Br. at 3. Furthermore, the Local charges, Peoples Gas stated in these proceedings that "it plans no new initiative or program to address replenishment issues," and "customers will pay the price for such failures, whether in the form of lengthened outages, lesser quality service, or worse." Id. at 4.

Peoples Gas replies that the Plan "inappropriately would circumscribe and invade the role of management." PGL-NS Init. Br. at 228. The result, PGL charges, would be "less flexibility" for Peoples Gas management and "possible disputes." Id. at 230. As for the Local's willingness to subordinate hiring to technological obsolescence and infrastructure improvements, Peoples Gas avers that the Local "did not provide specifics." Id. at 228. In fact, Peoples Gas suggests, the Plan would undermine, rather than promote, the efficiency favored by the legislature in Section 1-102 of the PUA[82]. As Peoples Gas puts it, the very situation criticized by the Local - "doing more with fewer people" – "sounds like efficiency." PGL-NS Rep. Br. at 177. Finally, Peoples Gas characterizes the Local's evidence as anecdotal and inadequate to demonstrate systemic or chronic problems affecting safety. Id. at 178.

4. Commission Conclusion re: Merits of the Plan

The Commission finds that the Local has raised serious questions regarding the impact of Peoples Gas's staffing and repair practices on employee and public safety. The Local alleges that Peoples Gas "encourages the frequent use of temporary repairs," that temporary repairs are used "routinely and extensively," that the interval between temporary and permanent repairs is "growing significantly," and that such practices contravene Peoples Gas's Field Service Manual, compromise public safety and are attributable to insufficient staffing among the top-tier employees that must complete permanent repairs. The gravity of the circumstances alleged by the Local is only heightened by the presence of the Local's membership on the "front line," where the potential for harm to life, health and property is evaluated first-hand. We have no doubts about the credibility or the sincerity of the Local's presentation in these proceedings.

Nonetheless, the Commission is not ready to conclude, based on the Local's ground-level view, that Peoples Gas's staffing and repair practices do jeopardize, beyond an unavoidable margin of error, either the safety of workers and customers or service reliability. While the Local's description of the response to serious (Class I) gas leaks at a Chicago hospital is unquestionably troubling, it remains, as Peoples Gas

[82] 220 ILCS 5/1-102.

avers, a single example of the systemic deficiencies the Local describes, which, we recognize, is all the Local intended it to be. Additionally, Peoples Gas's decision to hire eight outside contractors to perform seasonal and, even from the Local's standpoint, routine tasks is not necessarily indicative of inadequate staffing or unsafe or unreliable conditions. PGL-NS Rep. Br. at 178. In order to immediately implement the Local's proposed staffing Plan, the Commission would need precise aggregate data regarding the practices reported by the Local, confirming that health and safety are compromised and that the Plan is likely to provide a remedy. Consequently, on the record provided here, the Commission will not require implementation of the Local's staffing plan.

The Local's audit recommendation is another story, however. Our hesitation to impose the Local's Plan is not based on evidence disproving its efficacy, but, rather, the absence of systemic statistical evidence that would have persuaded us to adopt the Plan or something similar today. Instead of furnishing meaningful record evidence to reassure the Commission and the public that safety and reliability are not at risk due to staffing deficiencies, Peoples Gas trivialized the efforts of its own employees to call attention to important concerns. The Commission addresses the proposed audit in the next section of this Order.

B. Audit of Repairs and Staffing

1. Parties' Positions and Applicable Law

As noted above, the Local requests an independent audit of: (a) work order response times and backlogs (inclusive of temporary repairs) at Peoples Gas; and (b) staffing levels among the workforce that handles those repairs. The Local and Peoples Gas concur that express authority to require an audit resides in Section 8-102 of the Act[83], which states:

> The Commission is authorized to conduct or order a management audit or investigation of any public utility or part thereof. The audit or investigation may examine the reasonableness, prudence, or efficiency of any aspect of the utility's operations, costs, management decisions or functions that may affect the adequacy, safety, efficiency or reliability of utility service….

The parties disagree, however, about whether the necessary findings for a Section 8-102 are supported by the evidentiary record here. Section 8-102 authorizes an audit by the Commission "only when it has reasonable grounds to believe that the audit or investigation is necessary to assure that the utility is providing adequate, efficient, reliable and safe least-cost service."

As proof that "reasonable grounds" for an audit or investigation are absent, Peoples Gas states that it has already "established a compliance monitoring group that

[83] 220 ILCS 5/8-102. The Commission also has the general power to "inquire into the management" of a public utility to "keep itself informed as to the manner and method in which the business is conducted…and the manner in which the[] plants, equipment and other property…are managed, conducted and operated." 220 ILCS 5/4-101. Similarly, a utility "shall furnish" to us "all information required by it to effect the provisions of this Act, and shall make specific answers to all questions submitted by the Commission." 220 ILCS 5/5-101.

audits compliance with [Peoples Gas's] Field Service Manual." PGL-NS Rep. Br. at 179. But other than the bare oral declaration during cross-examination that such a monitoring group is now "performing audits," (Tr. 228 (Doerk)) Peoples Gas provides no information. Thus, Peoples Gas does not indicate whether the group scrutinizes the work order backlogs, completion times and repair staffing the Local addresses. Peoples Gas also testifies that it is already "working with a Commission hired consultant reviewing all [Peoples Gas's] pipeline safety related activities." PGL-NS Ex. 2.0 at 6. But, again, Peoples Gas offers nothing more, and the Commission cannot – in view of the Local's detailed evidence andPeoples Gas's silence - fulfill its obligations regarding customer and employee safety by simply assuming that a pipeline consultant is reviewing, for example, leak repairs inside or adjacent to customer premises.

2. Commission Conclusion

Importantly, Peoples Gas acknowledges that it has not compiled information concerning the "use, frequency and average duration of temporary repairs." Tr. 223 (Doerk). Consequently, the record provides no statistical information to either justify the Local's One-for-One proposal or to dismiss the Local's audit request. Therefore, the inferences suggested by the direct observations and anecdotes of Local members - that permanent repairs are not performed soon enough because qualified employees are busy with other work, and that public and employee safety are therefore compromised – are not rebutted. Moreover, there is history ofPeoples Gas's safety-related deficiencies in the record. Peoples Gas confirms that it was fined for failure to conduct required inside safety inspections during the period from 2000 through 2004. Id. 247-48. The Commission concludes that there is reasonable ground to require an appropriately tailored audit of certain aspects of Peoples Gas's operations[84].

So that the audit results are useful to interested parties, and so that Peoples Gas has clear directions, the Commission will sharpen the focus of the Local's audit request ("work order response times and backlogs (inclusive of temporary repairs)"). The safety concerns raised by the Local's testimony, taken as a whole, are associated with the frequency of temporary repairs and the time interval between temporary and permanent repairs[85]. Consequently, the audit should quantify, for each of the calendar years 2003 through 2007, the total number of gas leaks repaired by Peoples Gas, and the total number and percentage of those in which temporary repairs were used. Separate data should be presented for each class of gas leak (i.e., Classes I through III). The audit should also quantify the percentage of all gas leaks repaired and number of temporarily repaired gas leaks for which permanent repairs were completed in one, two, three, four,

[84] On exceptions, PGL asserts that the stated ground for the audit required here is "one particular leak [at a Chicago hospital]." PGL-NS BOE at 85. That is patently incorrect. The Local testified to *patterns and practices observed and performed by its membership* while in PGL's employ, which were fully described throughout Section XII of this Order and are the basis for our audit directive.

[85] *E.g.*, "Our experience is that temporary repairs are used routinely and extensively throughout [PGL's] service territory, and that the period of time between when a temporary repair is implemented and a permanent repair is completed is growing significantly. This is not a tolerable state-of-affairs because gas leaks that are not fully repaired do not get better on their own, they can only get worse. In my experience and those of other Local 18007 employees, the Company does encourage the frequent use of temporary repairs as a stopgap measure to respond to work orders quickly." Local Ex. 2.0 at 13.

five, and more than five business days. Again, separate data should be presented for each class of gas leak[86].

With respect to staffing, the Local's audit request ("staffing levels among the utility workforce at PGL") also needs narrowing. The Local's testimony, taken as a whole, associates safety issues with insufficient staffing of "top-tier" positions among Peoples Gas's work force, particularly Senior Service Specialist No. 1 in the Service Department and Crew Leader in the Distribution Department[87]. Therefore, the audit should quantify, for each of the calendar years 2003 through 2007, the total number and percentage of gas leaks repaired by Peoples Gas in which a CL or SSS-1 participated, the total number and percentage of those in which temporary repairs were used, and the total number of such gas leaks assigned per CL and SSS-1 during each month. Separate data should be presented for each class of gas leak (i.e., Classes I through III).

Peoples Gas and the Local are the entities most familiar with the pertinent subject matter. Accordingly, the Commission encourages them to expand or reorganize - by mutual agreement - the focus of the audit to make its results as useful as is practicable. Any such expansions or revisions should be explained in the final report to the Commission. We also direct that the Natural Gas Pipeline Safety Section of our Staff respond affirmatively (within the limits of its resources) to any reasonable request from Peoples Gas and the Local for assistance in shaping and conducting the audit.

The audit shall be completed and its results submitted to the Commission's Staff within the 180 days after the entry of this Order, unless Peoples Gas and the Local mutually agree to a different submission deadline. Contemporaneous with such submission, Peoples Gas shall provide a copy of the audit results to the Local, subject to execution by the Local of a reasonable confidentiality pledge, if such pledge is requested byPeoples Gas. The audit results shall be attested to by the auditing party.

Although the Local requests an independent audit, the Commission sees no reason why Peoples Gas personnel should be precluded from performing the audit and attesting to their results. Regarding costs, the audit described above is not materially different from responding to discovery requests in proceedings like these. Peoples Gas should bear such costs and include them in its expense calculations in a subsequent rate case. If Peoples Gas, at its discretion, instead elects to hire an independent auditor, Section 8-102 states that "the cost of an independent audit shall be borne

[86] Peoples Gas curiously complains that the Commission is requiring "the reporting of specific statistics which were never addressed in the evidentiary record." PGL-NS BOE at 87. That is precisely the point. The Local provided troubling evidence of practices imperiling public health and safety and PGL provided no responsive evidence. Our authority to require data under such circumstances is extensively cited in this Order.

[87] *E.g.*, the Local "testified that lag times to complete permanent repairs are expanding, and that the use of temporary repairs is increasing. Based on experience in the field, the [Local] asserts that the reason for the lengthening lag is a shortage in the ranks of those highly-skilled employees without whom permanent repairs cannot be conducted." Local Init. Br. at 3.

initially by the utility, but shall be recovered as an expense through normal ratemaking procedures." By its terms, this is a mandatory cost allocation and recovery scheme and the Commission must implement it in this instance.

The Local also requests a commitment to expeditious action after the audit is completed. Local BOE at 18. We believe that is premature. We do not want to prejudge the results of the audit or rule out the prospect that the parties will craft their own remediation plan if the audit demonstrates that one is warranted. Instead, we will leave it to the Local, or Staff, or some other affected stakeholder, to request or initiate a new proceeding under the authority of the Act (much of it discussed above) based on the audit results. Insofar as public health and safety concerns are implicated, such proceeding could be conducted on an expedited basis.

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) Peoples Gas is an Illinois corporation engaged in the transportation, purchase, storage, distribution and sale of natural gas to the public in Illinois and is a public utility as defined in Section 3-105 of the Public Utilities Act;

(2) North Shore is an Illinois corporation engaged in the transportation, purchase, storage, distribution and sale of natural gas to the public in Illinois and is a public utility as defined in Section 3-105 of the Public Utilities Act;

(3) the Commission has jurisdiction over the parties and the subject matter herein;

(4) 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;

(5) the test year for the determination of the rates herein found to be just and reasonable should be the 12 months ending September 30, 2006; such test year is appropriate for purposes of this proceeding;

(6) the $2,327,999,000 original cost for Peoples Gas and the $369,442,000 original cost for North Shore of plant at September 30, 2006, as reflected on the Companies' Schedules B-1, Line 1, column D, are unconditionally approved as the original cost of plant

(7) for the test year ending September 30, 2006, and for the purposes of this proceeding, Peoples Gas' original cost rate base with adjustments is $1,212,274.000;

(8) for the test year ending September 30, 2006, and for the purposes of this proceeding, North Shore's original cost rate base with adjustments is $182,033,000;

(9) a just and reasonable return which Peoples Gas should be allowed to earn on its net original cost rate base is 7.76%; this rate of return incorporates a return on common equity of 10.19% and costs of long-term debt of 4.67, with a just and reasonable capital structure of 56% common equity and 44% long-term debt;

(10) a just and reasonable return which North Shore should be allowed to earn on its net original cost rate base is 7.96%; this rate of return incorporates a return on common equity of 9.99% and costs of long-term debt of 5.39%, with a just and reasonable capital structure of 56% common equity and 44% long-term debt;

(11) Peoples Gas' rate of return set forth in Finding (9) results in approved base rate net operating income of $ $94,073,000;

(12) North Shore's rate of return set forth in Finding (10) results in approved base rate net operating income of $14,489,000 ;

(13) Peoples Gas' rates, which are presently in effect, are insufficient to generate the operating income necessary to permit Peoples Gas the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(14) North Shore's rates, which are presently in effect, are insufficient to generate the operating income necessary to permit North Shore the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(15) the specific rates proposed by Peoples Gas in its initial filing do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; Peoples Gas' proposed rates should be permanently canceled and annulled consistent with the findings herein;

(16) the specific rates proposed by North Shore in its initial filing do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; North Shore's proposed rates should be permanently canceled and annulled consistent with the findings herein;

(17) Peoples Gas should be authorized to place into effect tariff sheets designed to produce annual revenues of $461,780,000 , including base rate and rider revenues, which represents a gross increase of $71,191,000 ; such revenues will provide Peoples Gas with an opportunity to earn the rate of return set forth in Finding (9) above; based on the record in this proceeding, this return is just and reasonable;

(18) North Shore should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $63,439,000 , including base rate and rider revenues, which represent a gross decrease of $213,000 ; such revenues will provide North Shore with an opportunity to earn the rate of return set forth in Finding (10) above; based on the record in this proceeding, this return is just and reasonable;

(19) the determinations regarding cost of service and rate design contained in the prefatory portion of this Order are reasonable for purposes of this proceeding; the tariffs filed by North Shore and Peoples Gas should incorporate the rates and rate design set forth and referred to herein;

(20) new tariff sheets authorized to be filed by this Order should reflect an effective date not less than three (3) days after the date of filing, with the tariff sheets to be corrected, if necessary, within that time period;

(21) Peoples Gas and North Shore should file a tariff sheet enabling transportation customers to return to their required baseload volume after a delivery reduction, even while a delivery restriction continues, as described in Section X.C.7 (b) of this Order

(22) the Utilities should perform an avoided cost study (or, at the Utilities' discretion, an embedded cost study) as described in subsection X.B.3. of this Order, which should be completed within 120 days of the date of this Order, and Rider SBO shall be revised in accordance with the results of that study;

(23) as required in subsection X.D.2(b) above, the Utilities should have customer consent processes in place and operational no less than 45 days after the date of this Order;

(24) all enhancements for the PegasysTM electronic bulletin board for North Shore and Peoples Gas, as addressed in the record in these proceedings, should be complete, fully operational and available for use by customers on or before August 15, 2008;

(25) Peoples Gas should conduct an audit of gas leaks and repairs in conformance with the Commission's directives in Section XI. B. of this Order, with the costs of the audit borne in the manner described in that section;

(26) Peoples Gas should, no later than 120 days from the date of this Final Order, submit to the Director of the Energy Division a report of procedures documenting how it allocates Manlove storage capacity and, how it ensures no harm to ratepayers from its allocation decisions, as is directed under Part V of this Order;

(27) the Utilities should include in the Rider VBA schedule the recommended language changes proposed by Staff and accepted by the Utilities, and as directed in Part IV and Part VII of this Order;

(28) upon conclusion of the Rider VBA pilot program, if the Utilities wish to make Rider VBA permanent, they shall file a general rate case;

(29) Staff should provide the Commission with an annual report on Rider VBA's effect on the Rate of Return, as directed in Part IV C. and Part VII A.; and

(30) the Utilities' Rider EEP should include an annual reconciliation procedure, provision for an internal audit, and a change to the monthly tariff date as Staff has proposed.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets presently in effect rendered by The Peoples Gas Light and Coke Company and North Shore Gas 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 The Peoples Gas Light and Coke Company and North Shore Gas Company on March 9, 2007 are permanently canceled and annulled.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company and North Shore Gas Company are authorized to file new tariff sheets with supporting workpapers in accordance with Findings 17 and 18 of this Order, applicable to service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company and North Shore Gas Company shall file a tariff sheet enabling transportation customers to return to their required baseload volume after a delivery reduction, even while a delivery restriction continues, as described in Section X.C.7.(b) of this Order.

IT IS FURTHER ORDERED THAT the Utilities shall perform an avoided cost study (or, at the Utilities' discretion, an embedded cost study) as described in subsection X.B.3 of this Order, which should be completed within 120 days of the date of this Order, and Rider SBO shall be revised in accordance with the results of that study.

IT IS FURTHER ORDERED THAT, as required in subsection X.D.2(b) above, the Utilities shall have customer consent processes in place and operational no less than 45 days after the date of this Order.

IT IS FURTHER ORDERED that all enhancements for the PegasysTM electronic bulletin board for North Shore Gas Company and The Peoples Gas Light and Coke Company, as addressed in the record in these proceedings, should be complete, fully operational and available for use by customers on or before August 15, 2008.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company shall conduct an audit of gas leaks and repairs in conformance with the Commission's directives in Section XI.B. of this Order, with the costs of the audit borne in the manner described in that section.

IT IS FURTHER ORDERED that no later than 120 days from the date of this Final Order, Peoples Gas shall submit to the Director of the Energy Division a report of procedures documenting how it allocates Manlove storage capacity and, how it ensures no harm to ratepayers from its allocation decisions.

IT IS FURTHER ORDERED that the recommended language changes proposed by Staff and accepted by the Utilities, as well as other changes articulated in Section VII(A)(1), shall be included in the Rider VBA schedule.

IT IS FURTHER ORDERED that, upon conclusion of the Rider VBA pilot program, if the Utilities wish to make Rider VBA permanent, they shall file a general rate case.

IT IS FURTHER ORDERED that the Utilities' Rider EEP shall include an annual reconciliation procedure, provision for an internal audit, and a change to the monthly tariff date as Staff has proposed.

IT IS FURTHER ORDERED that any motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the 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 this 5th day of February, 2008.

(SIGNED) CHARLES E. BOX

Chairman

CONNECTICUT

In Re United Illuminating Co., Docket No. 05-06-04, CONNECTICUT DEPARTMENT OF PUBLIC UTILITY CONTROL, Order (Jan. 27, 2006).

KeyCite Yellow Flag - Negative Treatment
Supplemented by APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE ITS RATES AND CHARGES - PUBLIC ACT 07-242, SEASONAL RATES, NON GENERATION-RELATED TIME-OF-USE PRICING AND RELATED RATE DESIGN ISSUES, Conn.D.P.U.C., September 29, 2008

2006 WL 316835 (Conn.D.P.U.C.), 246 P.U.R.4th 357

Re The United Illuminating Company

Docket No. 05-06-04

Connecticut Department of Public Utility Control

January 27, 2006

Before Betkoski, III, Downes, Goldberg, George, and Palermino, Commissioners.

BY THE DEPARTMENT:

I. INTRODUCTION

A. SUMMARY

***1** This full rate setting proceeding pursuant to General Statutes of Connecticut sections 16-19 and 16-244c(b)(2)(C) was initiated by The United Illuminating Company (UI) by way of an application filed on July 18, 2005. UI's application presented a rate plan for a period of four years through December 31, 2009. In its application, UI requested rates sufficient to recover UI's increased revenue requirements as requested by UI for each year of the rate plan. In this Decision, the Department makes pertinent adjustments to the revenue requirements requested by UI and approves new revenue requirements and rates that will allow for the recovery of appropriate revenue requirements or each of the four years of the plan. No adjustments were made to rates associated with the recovery of competitive transition assessment revenue requirements. The incremental revenue requirements approved by the Department and as requested by UI for the years 2006, 2007, 2008 and 2009 are as follows:
2006 $14,324,000 approved; $39,814,000 requested

2007 $4,302,000 approved; $3,576,00 requested

2008 $10,263,000 approved; $12,528,000 requested

2009 $6,710,000 approved; $8,611,000 requested

The allowed increases translate into total company increases compared to then-current rates of 1.98% in 2006, 0.6% in 2007, 1.4% in 2008 and 0.9% in 2009.

To more closely align rates with the cost of providing service, the Department will allow UI to increase residential Rate R rates by 3.0% in 2006 and Rate RT by the average of 1.98%. Rates to most commercial industrial customers and Street Lighting customers will be increased by less than the average increase approved. Rates GST and LPT shall be increased by 1.0% and Rate M and Rate U by .75%.

In addition, the Department approves herein an earnings sharing mechanism such that any earnings above the allowed return of equity are fully shared between shareholders and ratepayers. Thus, the Department allocates excess earnings on the basis of 50% to shareholders, 25% to ratepayers, and 25% to accelerate the amortization of stranded costs. This is to be calculated on a calendar year basis for each of the four years of the rate plan.

Central to UI's four year plan are costs associated with plans to consolidate its corporate headquarters and operations into a central facility. The Department weighed these projected costs, such as site procurement, construction and personnel relocation against projected costs for existing facilities, such as current lease payments, known deferred maintenance, renovation and expansion. The Department concludes that UI should be allowed to collect revenues associated with pursuing the centralizing of facilities during the term of the rate plan; however, there shall be a reconciliation and prudence review of the costs allowed herein.

Another ratemaking issue that this Decision addresses is the maturing of UI's workforce and attendant costs necessary to meet the projected decline in its trained workforce, especially for line workers and system electricians. The Department recognizes that there is a lead-time of approximately four years for a fully trained electric system employee and that UI will undergo targeted workforce recruitment, hiring and training costs during the period of the rate plan. The Department has allowed the Company to proceed with the hiring of new electric system workers as it proposed to avoid a future adverse impact on service caused by a potential shortage of electric system workers.

***2** The Department sets UI's capital structure at 48% common equity and 52% long-term debt and adjusts UI's return on equity downward from UI's requested 11.60% to 9.75%. This also reflects a downward adjustment from the currently allowed 10.45% and reflects more accurately UI's operating risk by having divested all of its generation plants, including nuclear; the fact that capital cost rates are at cyclical lows not seen since the 1960s, and the decline in the Company's business risk profile given that the Company receives a guaranteed return on its CTA assets.

The Department finds that the rates, as adjusted, for each year of the rate plan are just and reasonable and will provide UI with the necessary monetary stability to meet the Company's operating, financial, and budgetary requirements, while maintaining high quality service to its customers.

B. BACKGROUND OF THE PROCEEDING

The United Illuminating Company (UI or Company) has been operating under distribution rates established in the September 22, 2002 Decision in Docket No. 01-10-10, *DPUC Review of The United Illuminating Company's Rate Filing and Rate Plan Proposal* (01-10-10 Decision). The 01-10-10 Decision allowed UI a return on equity (ROE) of 10.45%. The 01-10-10 Decision called for an earnings sharing mechanism (ESM) to address excess earnings. All earnings above 10.45%, calculated by the cost of capital method, would be shared 50%/50% between the Company and ratepayers. Shareholders of UI retained 50%, while 25% was returned to ratepayers by virtue of bill surcredits and the remaining 25% was used to reduce nuclear stranded costs.

The Department of Public Utility Control (Department) notes that for the twelve months ended December 31, 2003, December 31, 2004, March 31, 2005, June 30, 2005 and September 30, 2005, UI's order No. 1 filings in Docket No. 76-03-07 show that the Company had ROEs of 9.5%; 11.19% (after sharing); 10.96%; 10.19%; and 10.28% for the twelve months ended December 31, 2003, December 31, 2004; March 31, 2005; June 30, 2005 and September 30, 2005, respectively. The pre-sharing ROE for UI for December 31, 2004, was 11.93%.

C. CONDUCT OF THE PROCEEDING

By Notice of Audit dated August 10, 2005, the Department conducted an audit of the books and records of the Company, at UI's offices, 157 Church Street, New Haven, Connecticut 06506, beginning August 29, 2005.

By Notice of Hearing dated August 23, 2005, pursuant to Connecticut General Statutes (Conn. Gen. Stat.) §§16-11 and 16-19, the Department held a public hearing on this matter on September 27, 2005, in the New Haven Hall of Records, New Haven, Connecticut 06510. Thereafter, the hearing continued on October 6, 7, 11, 12, 14, 17, 18, 19, 20, 24 and November 9, at the offices of the Department, Ten Franklin Square, New Britain, Connecticut 06051.

***3** By Notice of Technical Meeting dated September 19, 2005, the Department held a technical meeting to discuss the Company's Cost of Service Study on September 29, 2005, at the offices of the Department, Ten Franklin Square, New Britain, Connecticut 06051.

By Notice of Tour dated November 4, 2005, members of the Department toured UI's Electric System Work Center located at 801 Bridgeport Avenue, Shelton, Connecticut on Thursday, November 10, 2005.

The Department issued a draft Decision on this matter on January 11, 2006. All Parties and Intervenors were provided an opportunity to file written exceptions to and present oral arguments on the draft Decision.

D. PARTIES AND INTERVENORS

The Department designated The United Illuminating Company, 157 Church Street, New Haven, Connecticut 06506-0901 and the Office of Consumer Counsel (OCC), Ten Franklin Square, New Britain, Connecticut 06051, as Parties to this proceeding. Intervenor status was granted to the Office of Attorney General (AG), Ten Franklin Square, New Britain, Connecticut 06051, the Connecticut Industrial Energy Consumers (CIEC), 540 Broadway, Albany, New York 12207, and the Retail Energy Suppliers Association (RESA), City Place I, 185 Asylum Street, 29th Floor, Hartford, Connecticut 06103-3469.

E. PUBLIC COMMENT

1. UI's Customer Notice

In September 2005, the Company sent a customer notice pursuant to Conn. Gen Stat. §16-19a to its customers advising them that it had filed an application with the Department on July 18, 2005, to increase its distribution rates and competitive transition assessment charges. The notice gave a brief explanation of the proposed increase and indicated that an evening hearing would be held on September 27, 2005, at the New Haven Hall of Records, 200 Orange St. New Haven, CT at 7:00 PM to record public comment with regard to the Company's application.

2. Public Hearing

On September 27, 2005, the Department conducted an evening hearing for the purpose of taking public comment from the general public concerning the Company's application.

Approximately 25 people were in attendance and 14 consumers spoke, all of whom were in opposition to the rate increase. Several of those who spoke were on fixed incomes and felt that with the other rising costs for gas and oil they would find it difficult to pay their bills. One woman referenced the UI stock market report that states that the Company had a good year. She said the Company is not hurting, its customers are. Others were of the opinion that the elderly would be those least able to pay and would therefore be affected the most. Those who spoke were also questioning why in its application the Company appears to be punishing the low kilo-watt users for trying to conserve with higher rates. One consumer said that the Company should be looking into more renewable energy such as wind and solar. Another person who spoke thought that all utilities should be municipally owned and controlled by the people of each district. Tr. 9/27/05, pp. 12-55.

3. Letters and E-Mail Correspondence

***4** The Department received 274 letters and e-mail correspondence regarding the Company's application. All were in opposition to the increase with the exception of one consumer who said she supported the rate increase if there was a proven need for improvements to the infrastructure.

Many of the customers who wrote to the Department were concerned with the increase because they felt their incomes have not kept pace with utility costs and, therefore, with the predicted rise in oil and gas prices this winter, the customers were fearful that they would be unable to pay their bills. A large percentage of those who wrote were upset with the proposed 20% increase to those customers who use 250 kWh or less. They felt the customers who would feel the most impact would be the elderly.

Other customers made suggestions that the Company should put more efforts into conservation and winterization. They also said there should be lower dividends to the shareholders and some concessions from the workforce.

There was also one letter from the Mutual Housing Association of South Central Connecticut with 44 signatures in opposition to the rate increase.

II. COMPANY PROPOSAL

By application received on July 18, 2005, (Application) UI requested approval of a proposed rate plan for a period of four years through December 31, 2009, effective January 1, 2006 (Rate Plan). In its Application, UI proposed changes to its distribution and competitive transition assessment (CTA) rates.

Pursuant to Conn. Gen. Stat. § 16-19 and § 16-244c(b)(2)(C), UI requested that the Department approve rates sufficient to recover the Company's increased revenue requirements for the years 2006, 2007, 2008 and 2009. The Company's request for distribution and CTA revenue requirements, as revised per Late Filed Exhibit No. 1, by year and cumulatively, is:

In its final, adjusted, rate request, UI requested increases to its total distribution revenue requirements of $39.814 million in 2006, or a 5.5% increase in base year revenue requirements calculated using then-current rates (*i.e.* what rates are expected to be absent this rate request) of $721.745 million, resulting in total proposed revenues of $761.559 million for that year. Further: in 2007, the proposed increase is .5% ($3.576 million divided by $706.308 million); in 2008, the proposed increase is 1.8% ($12.528 million divided by $713.149 million); and in 2009, the proposed increase is 1.2% ($8.611 million divided by $736.188 million). UI Brief, p. 4; *See* Total Company Schedule C-1.0 A-D for then-current annual rates.

The Company proposed that earnings be monitored on a calendar year basis. UI proposed that for the first year, revenue requirements would be determined for the period January 11 — December 31, 2006, and that new rates be put into effect February 1, 2006. The 2006 rates would be designed to recover the full revenue requirements for the period January 11, 2006 — January 31, 2006, with carrying charges for the January 11 — January 31, 2006 period. Thereafter, the revenue requirements would be determined for full calendar years, with a January 1 effective date each year 2007, 2008 and 2009. UI Brief, pp. 4 and 5. By letter dated December 19, 2005, UI stated its willingness to not implement rates until after the Department issues the final Decision with the caveat that rates would be collected effective January 13, 2006, the 180-day deadline.

***5** UI proposed changing its existing ESM that would provide a dead band above its allowed ROE and then allocate sharing of earnings on a 50/50 basis with the entire balance of ratepayers' share being credited to accelerated amortization of the stranded cost balance. Under UI's proposed ESM, the Company retains actual earnings above the authorized return, for the first 100 basis points, and shares on a 50/50 basis additional earnings above 100 basis points over the authorized return. UI would absorb the adverse impact of actual earnings below the authorized return except as the Company may seek relief in accordance with Connecticut statutes and established ratemaking principles (see UI Brief, p. 5). The Company proposed that the sharing would be calculated on a calendar year basis for each of the four years in the Rate Plan. The Company's standard filing requirements, supplemented by material supplied in Late Filed Exhibit No. 1, indicate that UI expects an ROE of approximately 11.6% annually through 2009.

The basic elements of UI's Rate Plan are further enumerated in Section III.A, Rate Plan.

III. DEPARTMENT ANALYSIS

A. RATE PLAN

UI's proposes that its Rate Plan be effective January 11, 2006, and run through December 31, 2009. The key elements of the Rate Plan are:

• Rates are established for each year separately, in accordance with the ratemaking principles of § 16-19e, based upon the costs, revenues and capital structure set for in the standard filing requirements (SFRs) for each year.

• In accordance with past practice, the equity return and capital structure for the CTA is adjusted to the approved distribution equity return and capital structure and CTA rates are adjusted accordingly.

• CTA rates are also adjusted for the impacts associated with the newly enacted Connecticut Corporation Business Tax (CCBT) surcharge.

• Transmission rates will be set and adjusted in a separate proceeding in accordance with FERC requirements and the recently-enacted ‘tracker‘ legislation in the State of Connecticut.

• The Company retains actual earnings (measured on a calendar year basis) above the authorized return, for the first 100 basis points, and shares on a 50/50 basis additional earnings above 100 basis points over the authorized return. The customers' share is credited to accelerated amortization of stranded cost balances.

• The Company absorbs the adverse impact of actual earnings below the authorized return except as the Company may seek rate relief in accordance with Connecticut statutes and constitutional ratemaking principles.

Source: Nicholas PFT, p. 5.

UI's Rate Plan proposes the following revenue requirements for the distribution and CTA rates:

UI states that rates must be set for each year of the four-year plan in accordance with § 16-19e(a)(4) principles. Forecasting is essential to calculating each ratemaking component in any rate proceeding, regardless of duration, and particularly important for a multi-year plan. UI states that it has substantiated each of its forecasts/projections for the rate year (2006) and for each subsequent year of the Rate Plan. UI Brief, pp. 9 and 10.

***6** UI believes that the OCC's consultants appear to be challenging the use of forecasts in setting rates, particularly for the later years of the Rate Plan. It is not clear to UI whether the OCC is challenging the concept of a four-year plan itself or simply attempting to depress the allowed expenses during the plan period. A challenge to forecasts, which are inherently necessary in multi-year ratemaking, would appear to put the OCC in direct conflict with the intent of the General Assembly as evidenced by the plain language of Conn. Gen. Stat. § 16-244c(b)(2)(C). UI Brief, p. 9.

1. Office of Consumer Counsel Position

The OCC believes that UI's proposed Rate Plan, with annual distribution and CTA rate changes for the period 2006-2009, should be rejected by the Department. Instead, the Department should opt for a traditional one-year revenue requirement determination. The OCC believes that the Conn. Gen. Stat. do not require the Department to approve a multi-year rate plan or specifically change rates in each of those four years. Tr. 10/24/05, pp. 2051 and 2052; OCC Brief, pp. 8 and 35.

The OCC's recommendation that the Department follow the traditional one-year approach in setting UI's distribution rates in this case is not in conflict with the Connecticut General Statutes and is a fair and reasonable approach to take in UI's case. While UI was exempt from filing a rate case prior to the start of the transitional standard offer (TSO) period because it completed a rate case in 2002, the OCC does not believe it was the General Assembly's intent to set rates for multiple years of post-TSO (Standard Service) rates prior to new legislation being introduced. Given the fact that the TSO period is about to enter its final year, setting rates for a four-year period that covers one TSO year and three years of Standard Service is not what the General Assembly would view as proper ratemaking policy. OCC Reply Brief, pp. 14 and 15.

The OCC agrees that it has proposed several revisions and modifications to the 'forecast' amounts contained in UI's filing. As indicated in its initial brief, the OCC found the level of support provided by UI for its forecasts, particularly for the latter years, to be lacking. While using future test years necessitate the use of forecasts or projections, the Department does not and should not blindly accept the Company's forecasts without a review of the reasonableness of the forecast amounts. The Company should be required to provide a reasonable level of support for its forecasts prior to such amounts being included in rates. The fact that the OCC has challenged many of the forecasted amounts contained in UI's filing does not put the 'OCC in direct conflict with the intent of the General Assembly …' as contended in UI's brief. OCC Reply Brief, p. 13.

The OCC does not agree with UI that it was the 'intent' of the General Assembly to require Department approval of changes in rates over a four year period when amounts for the latter years have not been supported and are subject to potential significant change. UI's filing is not based on a continuation of historical experience or 'status quo' operations. UI's filing incorporated significant project increases in capital expenditures that are well above historic experience and significant investment in infrastructure replacement that goes well beyond what has typically been done. These dramatic changes proposed by UI over the four-year period make the forecasts more speculative and likely much less accurate than what may be typical. In addition, based on testimony by UI's witnesses that the amounts could end up being different in the future from what was projected in the case, a four-year plan with annual changes in rates based on the filing presented by UI would not be appropriate. OCC Brief, pp. 35 and 36; OCC Reply Brief, p. 14.

***7** The OCC did calculate revenue requirements for each year of the Rate Plan. The OCC agrees that some of the corrections presented in Late Filed Exhibit No. 1 are appropriate based on the record in this case. However, the OCC does not agree that all of the revisions are reasonable, supported by the record, or appropriate. The OCC's calculations begin with UI's revised positions, as provided in its Second Revised Late Filed Exhibit 1. Based on the OCC's positions detailed in this brief, the overall UI distribution rate increases (decreases) for each year from present rates are ($2,408,000), ($3,746,000), $115,000 and $5,180,000 for the years 2006-2009, respectively. While the OCC has evaluated each of the four individual rate years contained in the Rate Plan, the OCC believes that the adoption of a four-year plan for UI should be rejected. The OCC believes that its adjustments result in a *pro forma* financial condition that is adequate and reasonable to sustain the legitimate needs of the Company and to cover reasonably and prudently incurred expenses, the result of efficient operations. With the *pro forma* adjustments the OCC is proposing, UI will have a reasonable opportunity to earn a fair and reasonable return on an appropriate level of investment. OCC Brief, pp. 7, 8 and 63

2. Office of Attorney General Position

The AG's position is that the DPUC should reject UI's Application to raise rates by a total of $61 million, or 8.5 percent, over the next four years. The Company's rate request is unreasonably inflated and calls for ratepayers to fund certain inadequately defined, discretionary projects that should not be undertaken in this time of record high energy costs. Many of the initiatives that are driving the Company's proposed rate increases over the next four years, most notably the central facility, are discretionary projects that should not be approved under the current conditions. These projects, however, may make sense in the future as conditions change in a manner that makes them more affordable. Thus, the DPUC should not lock in rates for UI for the next four years. Rather, it should set rates at levels that are just and reasonable at the present time and revisit the Company's rates as conditions warrant. UI's customers have to tighten their belts to pay for unprecedented energy costs in the coming months, and no less should be expected of UI. AG Brief, pp. 1 and 2; AG Reply Brief, p. 3.

The Department should reject UI's proposal for a four-year Rate Plan. The Company's future expenses and revenues are simply too speculative at the present time to set its rates for the next four years. Although Conn. Gen. Stat. § 16-244c(b)(2)(C) required UI to include a four-year rate plan in its rate Application, it does not require the DPUC to approve the Company's proposed four year plan, or any other four year plan for that matter. AG Brief, pp. 2, 3 and 5.

3. Rate Plan Analysis

a. Four-Year Rate Plan

***8** UI's Application was filed pursuant to Conn. Gen. Stat. §16-19, the traditional ratemaking statute, as well as §16-244c(b)(2)(C). The latter statute requires that an electric distribution company filing an application for an amendment of rates must include in such filing a four-year plan for the provision of electric transmission and distribution services. Inherent in such multi-year plans, where revenue requirements are set to recover expenses for each separate year of the plan, is the use of forecasting. Accordingly, UI used forecasts of capital expenditures and expenses for each year of the Rate Plan based on the Company's best analysis as to the level of expenditures the Company will make in the future.

The Department reviewed the Application and all subsequent data presented in support of the Company's forecasts. In the sections that follow, the Department makes adjustments to individual components of the Rate Plan, where the Department believes that UI did not prove its need for the requested amounts. Therefore, the Department concludes that it is appropriate to approve a four-year rate plan with adjustments. The approved Rate Plan will allow UI to recover costs at levels that are just and reasonable and ratepayers will know what to expect the distribution rate to be for the next four years.

b. Earnings Sharing Mechanism

UI proposes changing its existing ESM that would provide a dead band above its allowed ROE and then allocate sharing of earnings on a 50/50 basis with the entire balance of ratepayers' share being credited to accelerated amortization of the stranded cost balance. Under UI's proposed ESM, the Company retains actual earnings above the authorized return, for the first 100 basis points, and shares on a 50/50 basis additional earnings above 100 basis points over the authorized return. Nicholas PFT, p. 5. The Company proposes that the sharing would be calculated on a calendar year basis for each of the four years in the Rate Plan.

The OCC opposes the Company's changes to the ESM, which would allow UI to retain the first 100 basis points of earnings above its authorized return and that the customers' entire share of earnings exceeding the authorized return be credited to accelerated amortization of the stranded cost balance. OCC Brief, pp. 37-39. The OCC asserts that by allowing a public utility to retain the first 100 basis points over its authorized return entirely for shareholders would subvert the 100 basis point triggering mechanism, addressed in Conn. Gen. Stat. § 16-19(g), converting it entirely to additional earnings that benefit the Company only, with no benefits to ratepayers. The OCC notes that the Company testified that it was not aware of any utilities that have the hundred basis points dead band. *Id.*; Tr. 10/14/05, p. 1158.

***9** The OCC recommends that the current distribution of the earnings exceeding the authorized rate of return continue. OCC Brief, p. 39. Under UI's current plan, the ratepayers' share of the earnings exceeding the authorized return is split 50/50, with 25% going to accelerate the amortization of stranded cost balances and 25% going back to customers. The OCC states that this current split of ratepayers share between refunds and acceleration of the amortization benefits both the customers and UI, allowing for the potential of additional reductions to the unamortized stranded cost balances and also benefits the ratepayers currently through a reduction in bills when earnings in excess of the authorized rate of return continues. *Id.*

The Department shares the OCC's concerns with the Company's proposed alterations to its existing ESM. The Company's current ESM, which was approved by the Department in the 01-10-10 Decision, contains no dead band above the allowed ROE and allocates excess earnings, 50% to shareholders, 25% to ratepayers, and 25% to accelerate the amortization of stranded costs, should not be altered in this proceeding. Therefore, the Department finds that continuance of the basic mechanics of UI's current ESM is appropriate.

B. TEST YEAR/RATE YEAR

UI used the operating results for the 12 months ended December 31, 2004, as its test year. The Department accepts the test year as proposed.

UI presented a fully forecasted rate year, 2006. In addition, pursuant to Conn. Gen. Stat. § 16-244c(b)(2)(C), UI proposed a four-year Rate Plan from 2006-2009. Each year of the Rate Plan was built from the bottom up based on the projected operating and capital needs of the Company. The test year is used for comparison purposes to determine the reasonableness of the forecasted rate year.

UI provided detailed revenue, expense and rate base data for the rate year and each year of the Rate Plan to support its request for a distribution and CTA rate increase. UI also provided a set of SFRs (on a summary basis) for the Company as a whole. Schedules A — F. UI revised its proposed rate increase request in Late Filed Exhibit No. 1.

By letter dated December 19, 2005, UI stated its willingness to not implement rates until after the Department issues the Final Decision with the caveat that rates would be collected effective January 13, 2006, the 180-day deadline. Therefore, rates from date of implementation until December 31, 2006, would be set to collect rate year revenue requirements from January 13 through December 31, 2006, plus carrying charges from the period January 13 through the date that rates are actually implemented. UI states that waiting to implement rates until after the final Decision would be less confusing to customers. In the alternative, UI could implement the full amount of its rate increase request on January 13, 2006, subject to refund based on the final Decision.

***10** The Department agrees with UI that it would be less confusing to customers for UI to wait until after the final Decision to implement the actual approved rates. The Department allows UI to calculate carrying charges from January 13 until the date rates are changed. Therefore, the Department approves a rate year of January 13 through December 31, 2006. However, the rate increase will be implemented until mid-February. Therefore, the revenue requirements for the rate year will be recovered over approximately 101/2 months.

C. CENTRAL FACILITY

A major component of UI's rate increase request is its proposal to consolidate its operations into a central facility. In this section, the Department discusses the existing conditions and locations of UI's current facilities, UI's proposal to move to a central facility and other relocation alternatives. The Department also discusses the ratemaking implications. All rate base and expense adjustments related to the central facility proposal are carried into the final rate base and expense amounts approved in this Decision.

1. Central Facility Plan

a. Current Facilities

The Company currently has six separate work facilities located throughout its service territory. The facilities and their characteristics are as follows:

Existing UI Work Facilities

Size

Site	Function	(Sq. Ft.)	Assigned FTEs
ESWC [1] (Shelton)	Power Delivery, Asset Management, Operations, Safety, Environmental, Warehouse, etc.	135.7	334.4
Connecticut Financial Center (New Haven)	Corporate Offices, Audit & Compliance, Finance, Human Resources, Client Fulfillment & Services	200.2	308
IT Center (Shelton)	Information Technology functions	27.1	62.2
Middletown Ave. (North Haven)	Power Delivery, Field Engineering, Stockroom	18.8	46
East Shore (New Haven)	Revenue Meter Services, Standard Field Services	24.9	97
Gilbert Substation (New Haven)	**Substation, Transmission and Underground Work Center**	**8.1**	**18**

***11** Source: Late Filed Exhibit No. 50.

b. Central Facility Plan

UI plans to construct a new facility in Orange, Connecticut [2] that will serve as a centralized worksite that will effectively replace the other worksites. The Company has termed this proposed work center the 'Central Facility'. The application includes a $29.6 million capital expenditure during the Rate Plan period to support the consolidation of the other facilities into the Central Facility. UI states that the Application excludes costs associated with supporting multiple facilities and the cost to refurbish its main operations building in Shelton. Vallillo PFT, p. 13.

UI states that there are three primary objectives of the Central Facility consolidation: 1) to gain control of a critical strategic asset, 2) to reduce future occupancy costs, and 3) to improve the security of operations. UI proposes to implement its Central Facility strategy in two phases. Each phase involves construction of part of the Central Facility and relocation of UI personnel from other facilities. Relocations in conjunction with Phase 1 are planned for 2008, and those with Phase 2 are planned for 2012. Phase 1 consists of construction of an 188,000 square foot building at a net capital cost of $29.6 million. Phase 2, the costs of which will be incurred after the Rate Plan period, consists of construction of an additional 147,000 square foot addition at a capital cost of $28.7 million. UI's plan to implement these phases is summarized in the following table.

Central Facility Consolidation Plan

Phase	Site	Plans
1	ESWC, Shelton	Sell site
	Middletown Ave, North Haven	Allow lease to expire
	East Shore, New Haven	Retain site (substation)
	Gilbert Substation, New Haven	Retain site (substation)
2	Connecticut Financial Center, New Haven	Allow lease to expire
	IT Tech Center, Shelton	Allow lease to expire

***12** Source: Response to Interrogatory OCC-66; Late Filed Exhibit No. 50.

UI states that, if it does not implement the Central Facility strategy, there is a considerable backlog of deferred maintenance that needs to be accomplished at its existing sites to make them suitable for continued occupancy, particularly at the ESWC. The ESWC work includes replacing all overhead doors, replacing the furnace, replacing the pavement in the parking area and throughout most of the facility, upgrading the security fencing, rewiring the office building for greater emergency generator coverage, adding a larger capacity generator, replacing the roofs on all buildings, replacing the oil and gas tanks and gas pumps, replacing and upgrading the cooling tower and HVAC infrastructure, rehabilitating the overhead cranes and lifts in the garage, painting, cleaning and dredging the retention pond, and rebuilding the air handlers. UI states that the ESWC will also need to be renovated and expanded if the Company does not move to the Central Facility, including complete renovation of the office space to accommodate the increasing number of staff, construction of a new dispatch area meeting NERC and NPCC[3] standards, associated renovations to the security, heating, ventilation, and air conditioning systems, and relocation of the driveway. Tr. 11/9/05, pp. 2214-2219.

c. Alternatives

The Company presented two alternatives to the Central Facility plan in this proceeding.

• *Scenario 1 — Status Quo Plus.* The Company would pursue repairing and renovating ESWC and replacing the East Shore, Middletown Avenue and Gilbert Substation facilities. The ESWC would be expanded and renovated, and the East Shore, Gilbert Substation and Middletown Avenue work facilities would be combined into an 'Eastern Replacement Facility' to be built at an unknown site. The Company would continue renting facilities for the Connecticut Financial Center and the Shelton IT Tech Center.

• *Scenario 2-Decentralized Alternative.* The major functions of the Electric Systems divisions now at ESWC would be moved to the new hypothetical 'Eastern Replacement Facility', avoiding much of the ESWC renovation work. The ESWC would still need some remediation work, and would accommodate field functions formerly at East Shore, Gilbert Substation and Middletown Avenue work facilities. Response to Interrogatory EL-38.

The Company states that the revenue requirements for the Status Quo Plus would need to be included, and are greater on a cumulative basis in 2006 and 2007 than for pursuing the Central Facility. Therefore on a revenue requirements basis, this scenario is less favorable to customers than the Central Facility plan. Additionally, it is not clear what parcels of property of adequate size and suitable location would still be available by 2008. Also, from 2006 through the time of occupancy (likely to be 2011 at the earliest), the revenue requirements would be higher than the revenue requirements associated with starting the Central Facility now. UI states that Scenario 2 presents similar financial concerns to Scenario 1. Additionally, since the

Department will not have approved the Central Facility costs, the Company's rates will not include costs associated with actions necessary to proceed toward implementing the Central Facility plan. If these costs are not included in rates, the Company will not have the resources to move forward with the Central Facility. Proceeding on the basis of a hoped-for result of a limited reopening of a rate proceeding is too uncertain. UI maintains that the Central Facility could not reasonably be pursued under these circumstances. UI Brief, pp. 40 and 41.

d. Analysis

***13** The OCC states that the UI's central facility information has changed several times in this proceeding, and therefore questions the validity of the Company's plans. Further, the most viable alternative, the 'Status Quo Plus' plan, was presented late in the proceeding and was not able to be fully explored, and should not be included. OCC Brief, pp. 53 and 54.

The AG states that the Central Facility is a discretionary project that should not be undertaken in these financial times, since customers are already experiencing pressures from the rising cost of electric service. The AG further states that, if done at another time, the Central Facility strategy may make sense. Additionally, UI has not presented adequate information to justify the costs of the Central Facility, and the AG is also concerned about the economic effect on the city of New Haven that would result from the removal of the corporate offices. AG Brief, pp. 14-17.

The Department does not accept either the Status Quo Plus or Decentralized Alternative scenarios as a basis for setting rates in this proceeding. The Department acknowledges that there are significant issues regarding the Company's existing facilities and their capabilities to support the operations of the Company going forward; however, the alternatives are not sufficiently developed, and were submitted late in the proceeding only after extensive discovery on the Central Facility. Further, the concept of an 'Eastern Replacement Center' may not even be a viable alternative due to lack of available and suitable sites, as UI acknowledges. Response to Interrogatory EL-38.

In the hearings, Company witnesses described the physical deficiencies with the ESWC, including cramped working conditions, poor ventilation and a labyrinthine floor plan which decreases the efficiency of the work processes in the building. Further, space allocation to employees does not meet UI or industry standards. Tr. 11/9/05, pp. 2214-2245. The Department toured this facility on November 10, 2005, and corroborated many of the Company's representations. Although certain of the representations were not directly observable by physical observation (*e.g.* the need for dredging the sludge pond; other environmental work), the congested floor plan, material condition of the parking area, and poor ventilation were evident.

The System Operations Center (SOC) is an important component of the ESWC and the future Central Facility. The SOC is the control center where the transmission system controls and monitors are located and where distribution system switching is coordinated. Tr. 11/9/05, p. 2208. The current SOC is not in compliance with evolving requirements of NERC and the NPCC, which require substantially increased security capabilities such as a dedicated emergency generator, ventilation systems and increased cyber security capabilities. In the Central Facility strategy, the SOC may be located in its own bunker or under ground level. *Id.*, pp. 2210-2215.

***14** UI states that if it is ever to proceed with plans to consolidate its facilities, the appropriate time is now. Three factors converge that cause the Company to come to this conclusion:

• UI has deferred maintenance on its field force facilities pending determination of its real estate plans. At this point, a determination must be made on the deferred maintenance depending on which facilities strategy is pursued;

• UI is no longer constrained by the 10 year lease on the ESWC (since it has purchased it; and

• The number of available parcels of land to site the facility has markedly decreased.

Response to Interrogatory EL-38. UI further states that the Central Facility strategy, although capital-intensive, will break even after seven years, if it proceeds now. While the Central Facility strategy compared to the Decentralized Alternative results in a $2.5 million increase in revenue requirements during the term of the Rate Plan, it results in $26 million in savings over its first 20 years. Vallillo PFT, p. 13; Response to Interrogatory EL-36.

The Department believes that centralizing the Company's facilities in one location makes strategic sense and should result in synergistic efficiencies in the Company's operations. Further, it would enable UI to escape leases on certain of its facilities, especially the Connecticut Financial Center, and to establish a greater degree of operational control over its operations, and a consolidated facility should result in synergistic savings in operations and maintenance expense. The Department believes that UI should therefore pursue the Central Facility strategy. However, floor plans for the Central Facility have not even been drafted as of this time, nor has the approach to siting the SOC been decided, as discussed above. Tr. 11/9/05, p. 2233. Therefore, the Department cannot assume that the Central Facility plan will evolve and mature as the Company has proposed in the Rate Plan.

The Department addresses Central Facility costs and ratemaking treatment below. Because there will be a reconciliation of its costs in the future, which could potentially involve prudence issues, the Department believes it is important to closely monitor the status of the Central Facility as it evolves and as construction progresses. Therefore, the Department orders the Company to report on the status of the Central Facility each calendar quarter. Details of the information and timing of each report are provided in the order.

2. Costs and Ratemaking Treatment

The Department believes there are three possible options for the ratemaking for the Central Facility proposal. They are:

1) Approve a two-year rate plan without any costs related to the Central Facility. Assume the Department indicates its agreement with the concept of a central facility and encourages the Company to go forward with the Central Facility plan. As the costs for the Central Facility become more known and measurable, the Company can do as it feels necessary to request those costs.

***15** 2) Approve a four-year rate plan that includes no costs for the central facility. When the costs related to the Central Facility become more known and measurable, the docket would be reopened for the limited purpose of including those costs in rates.

3) Approve a four-year rate plan that includes costs for the Central Facility. At some date in the future, the docket would be reopened to true up the projected costs to actual or best known.

a. UI Position

The first two scenarios are in neither the Company nor customers' interest. Taking the Central Facility costs out of the revenue requirements means that the alternative costs associated with staying at ESWC would need to be added to the revenue requirements. This increases customer costs, while making it less likely that the Central Facility will ever be implemented. This could effectively result in higher costs to be recovered from customers for the next many years. A major benefit of the legislation's requirement to file a four-year plan is the ability to make and implement long term decisions. UI Brief, pp. 39 and 40.

The third scenario provides a good balance that would enable the Company to move forward with the Central Facility while assuring that the costs of the Central Facility are recovered fairly, in the interest of the Company and customers. The Company recognizes and shares the Department's concern that the costs recovered in rates reasonably reflect the Company's actual facilities costs. For that reason, UI does not object to the concept of a true-up, for the capital costs and regulatory asset. UI Brief, pp. 40 and 41.

The Company suggests the following ratemaking. Rates should be set for 2006-2009 on the basis of all of the Company's revenue requirements, including the Central Facility costs. The ESWC regulatory asset would be established in the anticipated amount of $7.1 million, with an annual amortization of $887,000 beginning in 2006. The costs to be trued up should be the capital costs specific to and attributable to the Central Facility (Phase 1), as detailed in response to Interrogatory EL-396, including its supplements, and the dollar amount of the regulatory asset. Because costs can vary from projections from month to month over the course of a project's construction, UI suggests that a comparison of capital costs be made when construction of Phase 1 is completed, or at a date certain that approximates the expected construction completion. UI suggests that the Department consider applying a 'collar' to its Central Facility capital costs for purposes of the true-up. For example, if the actual capital costs are within 10% (plus or minus) of the projected capital costs, there would be no true-up. If capital costs as constructed vary more than 10% from forecast, the Department could open a proceeding to consider the reasons for the variance. The regulatory asset amount could be trued up at the time of sale of ESWC on the basis of the actual sale price. The true-up could occur either in a limited reopening of this docket or in the docket that will be established to consider the sale. UI Brief, pp. 41 and 42.

***16** Providing in this docket for a true-up of capital costs and true-up of the regulatory asset will provide assurance to UI that the reasonable costs of the Central Facility are recovered, and that customers are protected if there is a significant variation in construction costs. UI Brief, p. 42.

b. OCC Position

The OCC's position is that UI's Central Facility plan should not be approved or included in the revenue requirements allowed in the current rate proceeding. OCC Brief, p. 9.

Of the three options the parties were asked to address, the two-year rate plan including no costs for the Central Facility would be the most beneficial to ratepayers at this time, but would be secondary to a one-year rate increase. It is the OCC's position that the Department should not be encouraging UI to follow the Central Facility approach at this time. Given the high level of energy costs and the significant level of projected increases in other components of the energy rates, now is not the time to undertake an expensive endeavor. If the Central Facility is truly the most economic and prudent option, then UI should not be further 'encouraged' to pursue that option beyond the general economics of the plan. OCC Brief, p. 36.

If a four-year rate plan is adopted with the Central Facility approach approved by the Department, which the OCC does not recommend, then the optimal approach at this time would be to exclude it from the rate determination and have a limited reopener at a future date when the amounts become more known and measurable, the timing is more known, and the amounts are less speculative in nature. Deferral of consideration to a later time via a docket reopener would hopefully allow for a more adequate, complete and accurate record on this project, and allow for parties a fuller review of the information presented late in this case. OCC Brief, p. 37.

The projected amounts that have been presented by the Company throughout this case associated with the Central Facility plan have also been a moving target, changing on many occasions. The frequent revisions, corrections, and updates to the various information provided on both the proposed Central Facility project and the alternative project (*i.e.*, Status Quo Plus), and the late timing of many of the changes, updates and corrections, has made the record on this project extremely questionable, confusing and imprecise. OCC Brief, p. 51.

With the recent repeal of the Public Utility Holding Company Act, UI may again be considered as a likely acquisition or merger candidate. If UI were to be acquired by a larger electric utility, a significant portion of the Central Facility may not be necessary. Approving a Central Facility at this time could effectively be creating a new category of 'stranded costs'. OCC Brief, p. 54.

If a four-year plan is adopted with annual changes, the OCC recommends that the calculations presented by its consultants in Exhibit__ (L&A-1), Schedule B-1 be used to remove the impact of the Central Facility. This schedule was derived using the information available and presented in the record and would be a reasonable estimate of the impacts of the removal of the Central Facility. OCC Brief, p. 55.

c. AG Position

***17** The AG states that the Department should not allow UI to collect in rates the costs associated with its proposed, but ill-defined Central Facility project. The central facility is a discretionary project that should not be undertaken in these lean financial times. AG Brief, pp. 2 and 6.

If forced to choose among the three ratemaking options, the AG prefers Option No. 1, but with the caveat that the DPUC should not encourage the Company to pursue the Central Facility plan at this time. Rather, the Department should completely re-evaluate these plans in the future in light of the then-current economic conditions facing UI and its customers. AG Brief, pp. 17 and 18.

d. Analysis

UI presented a tremendous amount of evidence in support of its Central Facility proposal. However, the evidence was not based on known and measurable costs, but on a proposal that has too many variables to be considered accurate or reasonable. The Department is not convinced that if it approved UI's proposal without modification, UI could complete the project as contemplated and ratepayers would pay costs that were no more than just and reasonable. Through the last day of hearings, UI had not contracted to purchase a site to construct the Central Facility and had no contracts or commitments in place to complete the construction of the facility. Therefore, the Department requested that the parties brief various ratemaking options as presented above.

UI testified that it was close to signing a purchase and sale agreement (PSA) with a property owner for a site in Orange. Tr. 11/9/05 (Confidential), pp. 2363-2365. Therefore, the Department held open the evidentiary record to allow UI time to execute the PSA. On December 8, 2005, UI submitted a signed PSA. Response to Interrogatory EL-34, Supplemental.

The signed PSA gives the Department greater assurance that UI will proceed with the Central Facility plan. While actual costs are not currently known, the Department believes it is reasonable for UI to proceed with its plan and include in rates UI's projected costs for the Central Facility plan. However, the Department understands the OCC's and the AG's concerns that rates should not include speculative costs. Although the Department is approving this four-year Rate Plan, it recognizes that there is a risk that ratepayers contribute an amount greater than is necessary for the Central Facility. It is also important that UI is assured of recovery for prudently incurred costs. Therefore, the Department believes that it is appropriate to allow UI to create a regulatory asset or liability for the variance in actual prudent Phase I costs compared to the amounts allowed herein. The disposition of the regulatory asset or liability will be determined in UI's next rate case.

UI's response to Interrogatory EL-396, Second Supplement identifies Central Facility specific revenue requirements of $3,730,000, $4,506,000, $9,956,000 and $8,398,000 for 2006-2009, respectively. UI shall file the actual capital costs when construction of Phase 1 is completed. The filing shall also include actual to date and projected operating and maintenance (O&M) expenses through the Rate Plan period. The filing shall include an itemization and description of all costs and shall identify rate base and expense impacts. The Company shall include support for actual and projected capital and O&M expenses as is available, including contracts. In addition, coincident with the status reports filed no later than July 30, 2006, 2007 and 2008, UI shall provide the Department with an update of its actual and projected remaining capital and O&M expenses for the Central Facility.

***18** The Department does not agree with UI that only capital costs and the ESWC regulatory asset should be subject to review. The Central Facility O&M expenses submitted in this proceeding are based on estimated square footage and International

Facilities Management Association first quartile metrics for key operating costs. *See* response to Interrogatory EL-325. The Department believes the regulatory asset or liability should also be reflective of prudent Central Facility O&M expenses. *See* the discussion, below, regarding how the ESWC regulatory asset is treated in rates.

The Department also does not believe applying a collar to UI's Central Facility capital costs is warranted in this case. UI is being given the benefit of knowing that prudently incurred Central Facility costs are and will be included in rates; therefore, the Department will review all actual capital and O&M amounts in its review of the regulatory asset or liability created above.

In summary, the Department allows UI to recover in rates its projected Central Facility costs during the Rate Plan while according ratepayers necessary protections.

3. ESWC Regulatory Asset

a. UI Proposal

UI intends to sell the ESWC in 2008 and requests to create a regulatory asset in 2006 for the projected $7.1 million loss on the projected sale. The net book value of the ESWC, including leasehold improvements, will be $15.1 million at December 31, 2008. When UI purchased the ESWC in 2004, the property was appraised at $8 million. UI received a verbal update from its real estate strategy consultant that the value of the property is still expected to be approximately $8 million in 2008. Schedules B-6.2 and C-3.35; responses to Interrogatories EL-78 and OCC-67; Late Filed Exhibit No. 58.

In addition to including the regulatory asset in rate base, UI included $887,000 in annual amortization expense. UI proposes to begin the amortization in 2006 and continue for eight years, which is the remaining life of the prior lease. From 2006 through 2008 UI also depreciates the plant asset at its current rate. Schedule C-3.35; response to Interrogatory OCC-67.

The ESWC lease initially called for lease amounts ranging from $3.8 million to $4.5 million for the ten years 1994-2003, followed by an additional five years at $5.4 million. The Company renegotiated the lease on favorable terms in 1994. The renegotiated lease provided for lease payments of $1.7 million per year for the first ten years, followed by lease payments of $3 million per year for the remaining ten years. The renegotiated lease provided an option for UI to purchase the building at the ten year lease point, for a pre-set price of $16 million. The lease buyout price of $16 million was less than the sum of the remaining lease payments. UI stated that each of the Company's actions, including the buyout, has resulted in lower costs being passed on to customers. Response to Interrogatory EL-76; Late Filed Exhibit No. 59

***19** Accordingly, if the Company sells ESWC as part of the Central Facility plan, UI believes it is appropriate to establish as a regulatory asset the expected loss on the sale of $7.1 million. UI Brief, p. 39.

UI states that recovery of the ESWC regulatory asset is a critical part of the Central Facility plan. UI's witness testified that if the Company does not recover the projected future loss on the sale of the ESWC from ratepayers, it might not go forward with the Central Facility plan. UI also states that it is willing to true up the actual amount of the regulatory asset when the ESWC is sold. Response to Interrogatory EL-81; Tr. 10/14/05, pp. 1196 and 1236.

UI's witness later testified that if Department tells UI that it may recover the actual loss determined in the normal review of the sale of the ESWC, then the Company is willing to postpone the creation of the ESWC regulatory asset until that time. Tr. 10/17/05; pp. 1375-1378.

UI states that Generally Accepted Accounting Principles (GAAP) did not require a write-down of the ESWC plant asset in 2004 when UI purchased the ESWC at a price above market value. UI's financial statements reflect cost-based rate regulation in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, ‘Accounting for the Effects of Certain Types of Regulation,‘ and UI's regulated results satisfy the SFAS criteria. Application of SFAS No. 121, ‘Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of,‘ cited in the OCC Brief, requires a review of long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The Department approved the revenue requirements associated with the lease on the ESWC building in the 01-10-10 Decision, p. 43, and those revenue requirements cover the costs to be incurred after the purchase of the building. UI Reply Brief, p. 34.

UI also states that Conn. Gen. Stat. § 16-245e(h)(4)(C) does not preclude the establishment of a distribution regulatory asset or limit the Department's authority to consider sales of property. UI is not seeking to increase stranded costs. UI Reply Brief, p. 35.

b. OCC Position

The OCC believes that UI's request to classify the future potential loss on the sale of the ESWC as a regulatory asset should be rejected. OCC Brief, p. 9.

The OCC finds the Company's proposal with regards to the ESWC to be unfair to the Company's customers and not in compliance with GAAP. Additionally, the requested pre-approval of a potential loss from disposition of property would be an inappropriate ratemaking practice that is not consistent with the Department's past precedence. Furthermore, the proposed treatment likely violates Conn. Gen. Stat. § 16-245e(h)(4)(C), where ‘the net proceeds that are above book value‘ for the ‘sale or lease of any real property after July 1, 1998.‘ are to be charged against nuclear stranded costs. OCC Brief, p. 57.

***20** The anticipated loss on the sale of the ESWC presented in UI's filing is not a known and measurable amount at this time. The exact sales price, if in fact UI ends up selling the facility, is not known at this time. UI should not be permitted to recover the potential future projected loss on this property that was just purchased less than two years ago, from ratepayers, particularly considering that UI has proposed that it begin recovery of the potential future loss in 2006, several years before it is anticipated that the property may even be sold. OCC Brief, p. 58.

The OCC believes that the loss on the property should have already been recognized by UI in 2004 on its books at the time of the purchase of the facility under GAAP. SFAS 121 requires that entities measure the long-lived assets held for sale as the lower of its carrying amount (net book value) or the fair value. If UI had followed GAAP at the time it acquired the ESWC, the potential future loss would have already been recognized on its books in 2004, which is prior to the rate years in this case. The ESWC would have been written down to its fair market value in 2004 and no loss would be realized in the future rate years if UI does, in fact, sell the ESWC. Thus, as the amount should have already been written-off in past periods on UI's books, it would not be appropriate to now recover this amount from ratepayers in future periods. OCC Brief, pp. 57-59.

c. AG Position

The DPUC should reject UI's proposal to create a regulatory asset for the ESWC at this time as improper and entirely speculative. It simply makes no sense to allow UI to begin collecting for its expected loss on the sale of this building in 2006 when the sale, should it actually happen, will not occur until some years later. AG Brief, pp. 14 and 15.

Although UI claims that its lease was back-loaded to the extent that its purchase in 2004 made financial sense the wisdom or prudence of signing such a lease to begin with is certainly open to question. Clearly, the DPUC should not be forced to approve the creation of a regulatory asset just because UI chose to sign an onerous lease for this building and then purchased the building at a loss to make its losses a bit less onerous. AG Brief, pp. 15 and 16.

Further, allowing UI full recovery of the losses it expects to incur with the sale of the ESWC would set a bad precedent, essentially inviting other utilities to sign onerous leases, then use those leases as an excuse to purchase the building and recover its losses from its customers. UI must be held to take financial responsibility for its decision-making. AG Brief, p. 16.

d. Analysis

UI's proposal to create a regulatory asset for the potential loss on the sale of the ESWC is premature. At a minimum, the regulatory asset should not be created until the actual amount of the loss is known. The sale might or might not occur in 2008, if at all. The actual sale price is unknown, and it is not reasonable to project a sale price of $8 million based on an appraisal completed in 2003.

***21** The OCC argues that under SFAS 121 UI should have reflected the loss on its books at the time it purchased the property. UI counters that its accounting is proper under SFAS 71. In this instance, the Department agrees with UI. The asset was not impaired at the time of purchase because UI was collecting revenues sufficient to cover the capital costs.

The Department also does not believe the AG's argument to deny the regulatory asset because the lease and purchase were onerous has merit in this case. Under normal circumstances, the Department would not allow the recovery of a loss on the sale of property. However, UI has requested recovery in this proceeding only to the extent that the sale is an integral part of its Central Facility plan. The Department must review all components, including the sale of the ESWC, of the plan for reasonableness. The Department reviews the loss on the sale of the ESWC as one component of the Central Facility plan.

UI stated its willingness to postpone the creation of the regulatory asset until the sale actually takes place. Because the sale of the ESWC is an integral part of the Central Facility plan, at the time of the actual sale, the Department will review the entire sale transaction, as is the case in any land sale, and allow UI to establish a regulatory asset at that time for the actual amount of loss on sale. If however, the property is sold for a net gain, then UI shall offset stranded costs by the gain as it does in all other land sales. The land sale proceeding will be about whether the property is necessary in the provision of utility service and did UI receive a market price for it. UI's purchase of the property was discussed above and it is not appropriate to review that transaction in the review of the sale of the property.

The Department denies UI's proposal to establish a regulatory asset beginning in 2006. Using the amounts in Schedule B-6.2, as revised in Late Filed Exhibit No. 1, the Department decreases rate base by removing the ESWC regulatory asset, less accumulated amortization, by $6,641,000, $5,767,500, $4,880,500 and $3,993,500 for the years 2006-2009, respectively. In addition the Department must reverse the increase to the accumulated depreciation that UI proposed to show the retirement on the projected remaining book value of the ESWC. That adjustment decreases the accumulated depreciation and increases rate base by $7,099,000 for each year of the Rate Plan.

The Department also removes the $887,000 amortization expense for each year of the Rate Plan.

D. RATE BASE

UI proposed a 2006 average distribution rate base of $400,379,000. In addition, the average rate base for 2007-2009, respectively, is projected to be $415,998,000, $460,143,000 and $464,280,000. UI later increased the 2006 average rate base by $1,270,000 and decreased the rate base for 2007-2009, respectively by $3,897,000, $12,969,000 and $3,399,000. Average rate base reflects a 13 month average. Schedule B-2.0 A-D; Late Filed Exhibit No. 1.

***22** The Department discusses adjustments to individual rate base components in the following sections. Central Facility is discussed in a separate section.

1. Construction Program

UI's construction program results in capital expenditures and plant additions during the term of the Rate Plan as follows.

5p

Proposed Capital Expenditures and

Plant Additions 2006-2009

(thousands of dollars)

	2006	2007	2008	2009
Capital Exp.	70,206	68,999	48,285	51,139
Plant Additions	48,391	89,414	45,287	48,963

Source: Schedules B-2.1 and F-7.0.

The OCC states that UI's filing includes exorbitant levels of projected additions to plant in service, and, if approved, will increase UI's total plant in service by 33% by the end of the Rate Plan period. According to the OCC, this is evidenced by comparisons of projected plant in service to historical levels, which are substantially less. Further, the Company did not provide sufficient level of detail or justification for the projected expenditures. The OCC reviewed the capital projects and recommends a number of capital projects be removed from the application, as discussed in more detail below. OCC Brief, pp. 42-51.

UI states that the OCC has overstated its capital projects and rate base projections, and that its capital program annual average in 2006 through 2009 is nearly identical to its historical annual average in 2002 through 2004. Additionally according to UI, the OCC did not provide discussion on safety, reliability or performance aspects of projects in its recommendations, and, since many projects are necessary for reasons other than cost savings, its analysis is incomplete. The Company also states that the OCC's analysis of gross plant additions did not take into account the fact that the plant balances in 2003 and 2004 are impacted by abnormally high plant retirements that occurred in those years. UI Reply Brief, pp. 27-31.

The Department believes construction programs should be analyzed by examining the needs the programs are intended to address, and the reasonableness of the solutions to those needs. Comparisons to historicals are useful to assist in determining whether the total expenditures are within a range of reasonableness, but even if projected expenditures vastly exceed historicals, to rationally analyze a company's proposed expenditures the Department must analyze them on a project-specific basis. Therefore, any adjustments based on gross comparisons to historical levels alone are not sufficient. Regarding the OCC's assertion that projected plant additions are much higher than historical, the Department notes that the plant additions are netted against retirements. Because additions can vary largely from one year to another, and because large amounts of retirements can offset the additions leading to a low net number, it is not valid to compare net plant additions between years. In 2003 and especially 2004, plant retirements were indeed very large ($19,212,992 and $33,268,115, respectively). Response to Interrogatory OCC-114. The Department therefore believes that comparisons to historical additions are not a valid determinant of future plant additions.

***23** With regard to capital expenditures, there are no large single-year roll-ins or offsets as there are with plant additions. Therefore, comparisons of projections to historicals are more straightforward. The projected average capital additions over the term of the Rate Plan are $59.6 million, and the historical capital expenditures for 2002-2004 are $60.4 million. Late Filed Exhibit No. 89. The Department concludes that the projected capital expenditure levels very closely approximate recent historical levels. The Department has reviewed the Company's capital program, and concludes that it is generally reasonable. However, certain programs were contested, require further explanation, and/or are adjusted by the Department. These are explained in more detail below.

a. Distribution Substation Conversion

The Company is implementing a program to eliminate older, lower voltage, high maintenance substations from its distribution system. Elimination typically consists of physical elimination of the substation and reconductoring the circuit. The Company is eliminating two or three substations per year each year during the Rate Plan. The Company has budgeted approximately $1.85 million per year for this activity. Response to Interrogatory EL-12.

The OCC states that the project will result in cost savings, which have not been reflected in the Application. Therefore, according to the OCC, the capital costs associated with it should be removed. OCC Brief, p. 47.

The Company states that there are both incremental costs and savings associated with the low voltage substation program; however, the net effect of the elimination of the substations is a savings of approximately $20,000 per year in avoided maintenance expenses, which are recorded in account 592, Maintenance of Station Equipment-Distribution. Late Filed Exhibit No. 19. The Department believes the correct adjustment is not to eliminate the project, but to ensure that savings are reflected in the application. Accordingly, the Department will reduce expenses to reflect the savings attributable to this program. *See* discussion in the section on expenses, below.

b. Air Circuit Breakers

This project consists of replacement of old substation Westinghouse DH type air circuit breakers with vacuum operated breakers. According to the Company, the old breakers are difficult and costly to maintain, parts availability is limited, and service support is increasingly difficult to obtain. The Company has budgeted $1,548,000 in 2008 and $1,554,000 in 2009 to replace breakers at one substation in each of these years. Response to Interrogatory OCC-65.

The OCC states that the project will result in cost savings, which have not been reflected in the Application. Therefore, according to the OCC, the capital costs associated with it should be removed. OCC Brief, p. 47.

The Department acknowledges that there are considerations relevant to utility operations other than just cost. In the case of this project, there are clear safety and reliability related considerations, as well as some cost savings of $4,248 per breaker per year. Late Filed Exhibit No. 17. The Department believes the correct adjustment is not to eliminate the project, but to ensure that savings are reflected in the application. Accordingly, the Department will reduce expenses to reflect the savings attributable to this program. *See* discussion in the section on expenses, below.

c. Underground Equipment

***24** UI's capital expenditure budgets include the following amounts for underground equipment:

Underground Equipment Budget

(thousands of dollars)

	2006	2007	2008	2009
Capital Exp.	1,739	3,045	5,249	7,300

Source: Response to Interrogatory OCC-65.

The OCC states that the Underground Equipment budget consists of two projects: Splice Chamber Rebuilds and Splice Chamber Roof Replacements. According to the OCC, the amounts budgeted for each of these projects in response to Interrogatory OCC-65 fall short of the total by approximately $1-2 million per year, and any excess should be eliminated since it was not accounted for by the Company. OCC Brief, p. 47. The Company states that Interrogatory OCC-65 only requested information on projects over $1 million, and that the shortfall is accounted for by other projects that were not requested by any party; therefore, it had no opportunity to account for the remainder. UI Reply Brief, p. 30.

The Department agrees with UI. Interrogatory OCC-65 only requested detail on projects 'listed over $1 million'; therefore, the Company was not provided the opportunity to account for the differential. The Department therefore will not make an adjustment in this area.

d. Workforce Automation

This project consists of three initiatives:

• Contractor Units — Implements standard work unit processes for contractors to enable more accurate estimating and planning;

• Designer Tool — Allows engineers and construction crews to prepare work order design and construction drawings directly in the Work Management System, to improve the efficiency of these personnel and improve responsiveness to customers;

• Mobile Computing — Provides field personnel with computer technology to enable transfer of work order requirements, order status, and order completion information, to improve the efficiency of communications between field personnel and office personnel.

The Workforce Automation project is budgeted for expenditures of $200,000 in 2006, $1,498,000 in 2007 and $1,186,000 in 2008. Response to Interrogatory OCC-65.

The OCC states that the project will result in cost savings, which have not been reflected in the Application. Therefore, according to the OCC, the capital costs associated with it should be removed. OCC Brief, p. 48.

Costs and benefits of the Workforce Automation project were discussed extensively in the hearing. This project is designed to control escalating costs, rather than directly result in cost savings. Absent the Workforce Automation project, additional costs would be incurred by the Company, which would otherwise be included in the Rate Plan. Tr. 10/11/05, p. 696. Therefore, to the extent additional costs are avoided, the savings are included. Further, the Department believes efforts to modernize and facilitate information-sharing within a utility's work processes has many benefits which will continue to be accrued into the future, including cost and customer-service benefits. Therefore, the Department will allow the costs of this program.

e. Financial System Implementation

***25** The Rate Plan includes capital expenditures of $3 million in 2007, $2 million in 2008 and $1 million in 2009 for the Financial System Implementation initiative, which is intended to upgrade/replace financial software. The OCC states that the Company does not have a specific plan for this initiative, and has not even completed a study to determine the plan. OCC Brief, p. 48.

The Company's financial data is currently maintained by Oracle software, and support for the current version of that software ends in March of 2006. UI states that it must take action to upgrade/replace the current software, and regardless of the course of action it takes, the projected expenditures must be made. UI Reply Brief, pp. 28 and 29. UI is currently studying converting the software to software by SAP, vs. the current Oracle Fusion version 8.9. Response to Interrogatory OCC-65.

The Department believes that the Company has demonstrated the need to make the required expenditures. Since support for the current version of the software will expire in the near future, it is obvious that action must be taken to maintain the financial system. The proposed expenditures appear to be in line with typical enterprise software packages of this magnitude, therefore the Department allows them.

f. Standard Desktop Refresh

The Rate Plan includes capital expenditures for refreshing approximately 1000 employee desktop computers of $2,457,000 in 2006, $73,000 in 2007 and 2008, and $2,412,000 in 2009. The OCC states that a full refresh in 2009 is unreasonable, given that the Application already includes a full refresh in 2006, and that it had been more than four years since the prior refresh. Therefore, according to the OCC the cost of the 2009 refresh should be removed. OCC Brief, pp. 48 and 49.

UI states that three years is the standard cycle for desktop refresh, and that the three years coincides with the warranty expiration on the new systems. Further, UI will risk incurring hardware/software issues if the three-year interval is exceeded. If the desktop refresh project is removed for 2009, then maintenance expenses must be added and $2,603,000 must be added back to plant in service for the computers that are not retired. *See* Schedule B-2.1 D. UI Reply Brief, p. 28.

The Department agrees with the OCC. Computer technology is not presently evolving at such a rapid rate that current desktops will be obsolete in three years. Furthermore, given the Company's expanding capital requirements in many other areas it should be reasonable to postpone the refresh another year, as seems to have been done with the prior refresh. The Department does not believe a four-year interval between refresh would harm the Company's operations. The Department, therefore, removes the incremental $2,339,000 in capital expenditures in 2009 for this project. Assuming the additions are added at the midpoint of the rate year, then plant in service is reduced by $1,170,000 for 2009. The Department also makes the related adjustments to the reserve for depreciation and depreciation expense. The Department notes UI's concern with the warranty expiration, which will result in the Company incurring some additional expense. The Department will make an adjustment in the expense section, below.

***26** While the Department agrees with UI's claim that $2,603,000 must be added back to plant in service for the computers that were assumed retired in 2009, accumulated depreciation must also be increased by the same amount. Therefore, there is no net impact to rate base from adding back the computers that were assumed retired in 2009.

g. Transmission-Related Projects

UI's initial filing included rate base treatment of a number of projects that were transmission-related but were initially assigned to distribution plant. The Department identified several such projects and requested a review of all capital projects to identify those that were appropriately assigned to transmission. Tr. 10/11/05, p. 716. The Company identified those projects to be reassigned from distribution to transmission and provided it in Late Filed Exhibit No. 20. The projects include Transmission Meters, Relay Communications Replacement, and one small reimbursable project. The reassignment results in a reduction in distribution rate base additions for 2004 of $447,884, and subsequent reductions in rate base. The revenue requirement impact of these adjustments is as follows:

Distribution Projects Reallocated to

Transmission Rate Base Impact

($ in thousands)

	2006	2007	2008	2009

Rate Base Adjustment	(423)	(406)	(389)	(373)

Source: Late Filed Exhibit 1-1.

Additionally, 2009 rate base includes distribution work related to the Middletown/Norwalk transmission project that was not previously included in the application, and results in an increase in 2009 average rate base of $202,000. Because UI included the rate base adjustments in Late Filed Exhibit No. 1, the Department does not make an additional adjustment.

2. Accumulated Depreciation

As discussed in the Depreciation Expense section, below, the Department made changes to UI's depreciation study. Consequently, the Department must also adjust accumulated depreciation. Because the change to depreciation expense is the result of changes to the depreciation study and not additions to plant in service, the corresponding decrease to accumulated depreciation is also for a full year and equals $130,300 during each year of the Rate Plan.

As discussed above, the Department adjusted plant in service for changes made to UI's construction program. Consequently, the Department must also adjust accumulated depreciation. UI's depreciation study indicates that computers have a four-year depreciable life. Schedule H-1.6, p. 18. Therefore, the corresponding decrease to accumulated depreciation is $292,500 for 2009.

Therefore, the total decrease to accumulated depreciation is $130,300 for 2006, $260,600 for 2007, $390,900 for 2008 and $813,700 for 2009.

3. Accumulated Deferred Income Taxes

***27** Because of the increase in the Storm Reserve Account, discussed in expenses, below, the ADIT balances for this item are increased, thereby decreasing rate base, by $123,000, $367,000, $611,000 and $855,000 in 2006, 2007, 2008 and 2009, respectively.

Due to the decreases in accumulated depreciation of $130,300, $260,600, $390,900 and $813,700 in years 2006 through 2009 aforementioned, the Department has calculated increases in the ADIT balance for this item of $161,000, $248,000, $215,000 and $603,000 in 2006, 2007, 2008 and 2009, respectively. *See* Attachment to Late Filed Exhibit-47-1 relationships for calculation.

As a result of adjusting the Pension Liability account by $1.524 million, $4.113 million, $6.242 million and $8.483 million in years 2006, 2007, 2008 and 2009 as reflected in the Pension Liabilities section, the Department also adjusts the Pensions ADIT balances to reflect 41% of the Pension Liability adjustments. *See* Attachment EL-57-1. Therefore, the Department adjusts Pensions ADIT upwards (decreasing rate base) by $.625 million, $1.686 million, $2.559 million and $3.478 million in 2006, 2007, 2008 and 2009, respectively.

Accordingly, the total increases to the ADIT balances (decreases to rate base) are $909,000, $2,301,000, $3,385,000 and $4,936,000 for 2006, 2007, 2008 and 2009, respectively.

4. Capitalized Payroll

As indicated in the Compensation Expense Section, the Department made an adjustment that increased UI's capitalized overhead by $433,000 in 2006, $624,000 in 2007, and $621,000 in 2008 and 2009. This adjustment decreased UI's proposed compensation expense. Accordingly, it is appropriate to increase the Company's rate base by $216,500 in 2006, $745,000 in 2007, $1,367,500 in 2008, and $1,988,500 in 2009.

5. Working Capital

The Application included proposed allowances for working capital of $30.299 million, $27.999 million, $27.358 million and $31.692 million for 2006, 2007, 2008 and 2009, respectively. Schedule B-4.0 A-D. Subsequently, UI adjusted its proposal downwards by $862,000 per year to reflect prepayments for regulatory commission expense, insurance and postage. This results in adjusted proposed working capital of $29.437 million, $27.137 million, $26.496 million and $30.824 million for 2006, 2007, 2008 and 2009, respectively. Response to Interrogatory OCC-121, Attachment OCC 121-1, Revised Schedule H-1.5 A-D.

In determining its working capital requirements, UI developed detailed revenue lead and expense lags for all significant cash inflows and outflows utilizing test year 2004 as a basis. The resultant lead/lag factors were applied to projected rate year revenues and proposed expenditures. UI's analysis calculated the daily revenue lead by examining actual service, billing and collection timing determinants for all revenue sources. Daily expense lags were developed by class and calculated in one of four ways:

1. by specifically examining the actual service period and payment dates — covering 76% of the expense class population;

***28** 2. by utilizing prior Department Decisions for guidance — covering 17% of the population;

3. by using previously approved factors when the expense class was represented by a very large volume of invoices and when the lag would not be expected to change significantly — covering 4% of the population; and

4. by assuming no lead or lag for miscellaneous items — covering 3% of the population.

UI removed the transmission working capital requirement using the FERC-approved methodology to calculate the transmission portion based upon test year 2004 data. Lead/Lag Study Cover Sheet.

The OCC indicates that the Company's lead/lag analysis wrongly reflects the date that bills are paid instead of due dates, and cites to this method's inappropriateness as reflecting the Department's Decision dated March 9, 1988, in Docket No. 87-03-06, *Application of The Southern Connecticut Gas Company to Increase Its Rates and Revenues* (1988 Southern Decision). Further, UI removes the amount attributable to transmission based on a formula, not a lead/lag approach. Therefore, the net result is a working capital requirement that is determined by netting two different methodologies. Accordingly, the OCC recommends calculating working capital based on allowing 45 days for working capital and allowing 10 days for energy costs per the 1988 Southern Decision, thereby reducing the Company's working capital requirement to $20.699 million. OCC Brief, pp. 64 and 65.

UI argues that the OCC seeks to have the Department change its established method of determining working capital, and states that it exactly followed the methodology approved by the Department in the 01-10-10 Decision and in the Decision dated December 17, 2003, in Docket No. 03-07-02, *Application of The Connecticut Light and Power Company to Amend Its Rate Schedules* (03-07-02 Decision). UI Reply Brief, pp. 40 and 41.

The Department compared the methodology used for UI in Docket No. 01-10-10 and finds that the Company has, indeed, followed the same methodology used in that docket. Further, UI incorporated the calculation changes made by the Department to various working capital elements in the 01-10-10 Decision. The Department also notes that a similar methodology was used in Docket No. 03-07-02 aforementioned. Therefore, the Department agrees with the Company's current methodology for calculating its proposed allowance for working capital in this proceeding because it is consistent with the Department's most recent electric utility rate case determinations.

Although the OCC's concern about using two different methodologies (lead/lag study and FERC transmission percentage) bears consideration, the Department finds that using the FERC-allowed percentage to allocate the rate base item for working capital to transmission is allowable in this situation. In future lead/lag studies filed by the Company, the Department will require that the itemized expenses used within the lead/lag study reflect proposed distribution expenses, not including transmission-related expenses, along with the working capital requirements associated with energy supply contracts not otherwise reflected in (GSC) rates. Nicholas PFT, p. 39.

***29** Although the Department accepts UI's methodology for calculating working capital requirements, it will adjust for the changes in distribution expenses between UI's originally proposed amounts and those allowed within this Decision.[4] The following decreases in working capital, reflected in the table below, result from taking the working capital component change, dividing that amount by 365 days, and multiplying that daily amount by the revised net lead/lag days reflected on Attachment OCC-121-1, Revised Schedules H-1.5 A-D (in $ thousands) for each rate year. Changes reflected on Second Revised Attachment Late Filed Exhibit No. 1-1 were also included in the calculation. These changes result in reductions in working capital of: $434,000 in 2006; $509,000 in 2007; $538,000 in 2008; and $609,000 in 2009.

In addition to the adjustments aforementioned, as a result of all Department adjustments, income tax expenses have decreased by $3.715 million, $3.668 million, $4.164 million and $4.236 million in 2006, 2007, 2008 and 2009, respectively, as calculated in the Income Tax Expense section. Therefore, the Department decreases the working capital required for income taxes by $149,000, $148,000, $167,000 and $187,000 in 2006, 2007, 2008 and 2009, respectively. Calculation per Attachment OCC-121-1, Revised Schedule H-1.5 A-D.

6. Storm Reserve

***30** As a result of the Department's downward adjustments to UI's proposed Storm Reserve Expense as explained, below, the Storm Reserve Account in rate base is increased by $300,000, $900,000, $1,500,000 and $2,100,000 in 2006, 2007, 2008 and 2009, respectively.

7. Pension Liabilities

UI proposed Pension Liabilities in rate base (rate base reductions) of $9.969 million, $19.504 million, $26.649 million and $32.949 million for 2006, 2007, 2008 and 2009, respectively. In the Pension Expense Summary, the Department reduced Pension, expenses by $3,048,500, $2,128,500, $2,128,500 and $2,353,300 in 2006, 2007, 2008 and 2009, respectively. The effect of these adjustments is to reduce the Pension Liability account ending balances for the rate years by an equivalent amount. See Attachment EL-57-1. Averaging the beginning and ending annual Pension Liability amounts to calculate the rate base effect, and using the newly calculated ending balance as the successor year's beginning balance, the Department calculates decreases in the Pension Liability account, thereby increasing rate base, by $1.524 million, $4.113 million, $6.242 million and $8.483 million in 2006, 2007, 2008 and 2009, respectively. *See* Schedule B-1.0 A-D for calculation basis.

8. Rate Base Summary

In summary, the Department increases the Company's average distribution rate base balance for 2006 through 2009 by $1,137,000, $4,392,000, $7,629,000 and $9,589,000, respectively. These adjustments include the rate base impacts discussed in the ESWC section. The resulting average allowed rate base for 2006 through 2009 is $402,786,000, $416,493,000, $454,803,000 and $470,470,000, respectively.

E. EXPENSES

UI proposed total operating expenses of $204,354,000, $212,680,000, $221,214,000 and $227,240,000 for 2006 through 2009, respectively. UI later increased its proposed operating expenses by $2,488,000, $2,078,000, $3,182,000 and $3,608,000 for 2006 through 2009, respectively. Schedule C-3.0 A-D; Late Filed Exhibit No. 1.

The Department discusses adjustments to individual O&M expense components in the following sections. Expense adjustments related to the Central Facility are discussed in the Central Facility section, above.

1. Advertising Expense

UI projected advertising expense in the amounts of $587,000, $604,000, $621,000, and $639,000 for rate years 2006 though 2009, respectively. The amount included in rate year 2006 is an 89% increase from the 2004 test year level of $310,000. Schedule C-3.2 A-D. UI reduced its test year and requested advertising expense by $26,000 for advertising and public relations related materials that it agreed were erroneously included in above-the-line distribution O&M expense. Response to Interrogatory OCC-122; Late Filed Exhibit No. 1.

UI increased advertising expense by $103,000 in 2006 and escalated the remaining Rate Plan years for customer education and promotion of the water heater control program. In the Decision dated March 30, 2005, in Docket No. 04-11-01, *DPUC Review of CL&P and UI Conservation and Load Management Plan for Year 2005* (04-11-01 Decision), the Department stated that UI has operated its water heater rental program for over 40 years and should be allowed to aggressively promote its water heater rental program and the benefits of Rate A to capture additional on-peak load reduction. However, the Department did not authorize the use of C&LM funds to subsidize this effort. *See* 04-11-01 Decision, p. 8. Response to Interrogatory EL-3.

***31** UI also increased advertising expense in the rate year for items such as general awareness and corporate communications ($65,000), customer service technologies such as IVR and web self-service ($62,000), economic and community development programs ($48,000) and a phone book listing ($13,000). Response to Interrogatory EL-302.

The OCC states that the Company did not fully explain or justify the need to increase the 2004 test year level by 89%. Further, the Company did not establish how this considerable increase in expense is necessary for the provision of electric service or beneficial to its distribution customers. Therefore, ratepayers should not be expected to pay for these significantly increased cost levels. The OCC recommends that advertising expense be held at the historic test year level, escalated in rate years 2007 through 2009 using the Company's the general escalation factors provided in response to Interrogatory EL-128. This would result in an advertising expense allowance of $284,000 in 2006, $294,508 in 2007, $305,405 in 2007 and $316,399 in 2009. These recommended amounts result in reductions to UI's proposed advertising expense of $277,000 in rate year 2006, $283,000 in 2007, $290,000 in 2008, and $297,000 in 2009. OCC Brief, pp. 97 and 98.

The Department agrees with the OCC that UI did not fully explain or justify the need to increase rate year advertising expense by 89% over the test year. As stated in the 04-11-01 Decision, the Department fully supports the Company's advertising efforts for customer education and promotion of the water heater control program. The Department also believes an important aspect of improving customer service is to promote the use of technologies such as IVR and web self-service. UI is allowed to significantly increase it's economic and community development programs, see discussion below, and the Department believes the funds will reach the intended recipients without an increase in advertising dollars. However, the Department believes the remaining increases in advertising expense are wish list items that do not increase UI's ability to provide reliable electric service to its customers.

Therefore, the Department allows UI to increase test year advertising expense by $165,000 ($103,000 + $62,000) for the rate year and escalated for the remaining Rate Plan years. Therefore the Department decreases advertising expense by $112,000, $115,000, $118,000 and $122,000 for the years 2006, 2007, 2008 and 2009, respectively.

2. Membership Dues

UI projected membership dues expense in the amounts of $1,409,000, $1,470,000, $1,511,000, and $1,555,000 for rate years 2006 though 2009, respectively. The amount included in rate year 2006 is a 120% increase from the 2004 test year level of $639,000. Schedule C-3.3 A-D.

UI testified that membership dues is one of the areas in the last few years that it has cut back in as the Company has managed to the bottom line. However, UI believes that the amount in the Rate Plan is a more reasonable level of support for these types of organizations. One area of increase for the rate year is contributing to economic development organizations. It's good business to be involved in these kinds of organizations and help them succeed in the area of economic development. Tr. 10/11/05, pp. 805-809.

***32** Specific programs and organizations include the Connecticut Economic Resource Center (CERC) for $200,000 and Bridgeport Economic Resource Center (BERC) for $36,000. UI testified that the Company will commit to funding these organizations if the Department allocates a specific line item to these organizations. Schedule WP C-3.3 A; Tr. 10/12/05, p. 925. The Company believes that its contributions to these organizations will support an effective statewide economic development strategy while also focusing on the needs of the key New Haven and Bridgeport regions. UI Brief, pp. 54 and 55.

UI also forecast to spend $289,000 for Electric Power Research Institute (EPRI). UI must pay for each program that it would like to participate in. Membership in EPRI allows the Company to gain access to research, analysis techniques and industry perspectives on topics such as aging infrastructure, distributed generation, and reliability management. However, as of the date of the hearings, UI had not yet committed to any of the EPRI programs for 2006. Tr. 10/12/05, pp. 925-933. UI believes that failure to provide resources for these programs will result in the Company facing its infrastructure challenges without the benefit of this research and industry perspectives. UI Brief, p. 55.

The Company states that it has demonstrated the reasonableness of its forecasted expenses for membership dues. Therefore, Department should allow the expenses as submitted. UI Brief, p. 55.

However, the OCC believes that the Company did not justify how the significant increase in expense from test year to rate year is necessary for the provision of electric service or the benefit to ratepayers that will result. For example, the OCC questions the benefits that are provided to the electric consumers from the Company's participation ($5,000 for 2006) in the United Telecom Council. Tr. 10/24/05, p. 2128; OCC Brief, pp. 93 and 94.

The OCC recommends using the test year actual cost as a base and escalating rate years 2006 through 2009 using the Company's general escalation factors provided in response to Interrogatory EL-128. This would result in membership dues expense of $662,000 in 2006, $686,000 in 2007, $712,000 in 2008 and $738,000 in 2009. Schultz and DeRonne PFT, p. 51. In addition, this amount should be increased further to reflect the funding of $255,000 under the CERC rate formula, which exceeds the amount in UI's filing, and the requested BERC funding contained in the filing. Therefore, the OCC recommends membership dues expense for each of the respective years, 2006 through 2009, of $953,000, $981,000, $1,008,000 and $1,035,000. These amounts result in reductions to the membership dues expense contained in UI's filing of $456,000 in 2006, $489,000 in 2007, $503,000 in 2008, and $520,000 in 2009. OCC Brief, p. 95.

The OCC also strongly recommends that the Decision identify specific dollar amounts for CERC funding, and that it require UI to fund at least those amounts annually. OCC Brief, p. 95.

***33** On November 4, 2005, the Department received a letter from CERC requesting that UI be allowed to recover the full amount of formula derived contribution to CERC in the amount of $255,000.

In general, the Department believes that membership in various community and research organizations makes good business sense. However, in this proceeding, the Department must balance the Company's rate year requests with the impact on ratepayers. The Department understands that UI curtailed its membership in groups in recent years and wishes to regain full involvement in and use of services offered by these groups. The Department doubts that full funding of UI's requested membership dues will translate into an equal amount of benefits to ratepayers. The Department believes that UI could choose not to participate in all the identified programs or could change the programs it participates in without a significant decrease in benefits. Further, while supporting local community organizations is generally good business, it is not necessary in the provision of electric service to ratepayers.

The Department will allow $1,184,000 for membership dues for 2006. This amount is midway between the Company's request and the OCC's recommendation. This allowance gives UI the opportunity to significantly increase its involvement in community and research organizations. Of the amount allowed UI must spend minimally $255,000 for CERC dues and $36,000 for BERC dues annually as it committed to during the 10/12/05 hearing. The Department escalates the allowed membership dues for 2007-2009 by the general escalation rates presented in response to Interrogatory EL-128. The allowed membership dues for 2007-2009 are $1,152,000, $1,184,000, and $1,218,000, respectively. Therefore, the Department decreases UI's request by $225,000, $318,000, $327,000, and $337,000 for 2006-2009, respectively.

3. Outside Services — Line Clearance Expense

Line Clearance expense includes all expenses necessary to clear or otherwise prevent vegetation from contacting electric distribution lines. The Company is increasing its Line Clearance Expense from $1,479,000 in 2004 to $2,266,000 in 2006. There are three primary reasons for the expense increase:

• A new program to remove vines that threaten electric facilities;

• A new program to remove hazardous trees outside the normal trim zone; and

• Expansion of the trim zone around conductors. Reed PFT, p. 19.

The OCC states that the increase is excessive because it assumes a level of spending for two new programs, and the planned trim costs were increased by over 40%, and that the Company did not provide sufficient explanation for the increase. The OCC provided its own breakdown of line clearance costs by category, which inflated 2004 costs for planned and spot trimming and provided some level of funding for the new programs. OCC Brief, pp. 100-101. The requested and the OCC-recommended funding for line clearance is as follows.

Line Clearance Expense

UI Requested and OCC Recommended

($ in Thousands)

	2006	2007	2008	2009
Requested	2,266	2,303	2,341	2,423
OCC Recommended	1,817	1,849	1,882	1,914

Source: Schedule C-3.5; OCC Brief, p. 102.

***34** The AG states that the Department should reject UI's proposed increases, since UI's previous budgets and expenditures have been adequate to maintain reliability, and the proposed increases are unsubstantiated and unjustified. First, according to the AG, UI's tree related outages have not increased in recent years. Second, UI has not shown a new need to institute a program to control vines, as prior programs have required the removal of vines in the past. Third, the Company has not shown a need for a hazardous tree removal program. The AG supports the OCC's recommendations for Line Clearance funding. AG Brief, pp. 21-23.

a. Vegetation Management and Reliability

The AG states that UI's reliability has not declined in recent years, nor have its tree related outages increased. Therefore, according to the AG, there is no reason to increase funding of UI's tree trimming program. AG Brief, pp. 21-23.

The Department provides a report to the Legislature on electric distribution company service reliability each year, in accordance with Conn. Gen. Stat. §16-245y. In its most recent report dated June 15, 2005 in Docket No. 05-05-05, *Annual Report to the General Assembly on Electric Distribution Company System Reliability*, the Department found ‘ …that UI's reliability has declined slightly since 1998. ‘Decision, p. 8. In UI's annual Transmission and Distribution Reliability Performance Report (TDRP) to the Department in Docket No. 86-12-03, *Long Range Investigation To Examine the Adequacy of the Transmission and Distribution Systems of the Connecticut Light and Power Company and The United Illuminating Company*, tree contact interruptions for the last five years are as follows:

Tree Contact Interruptions

2000-2004

2000	**2001**	**2002**	**2003**	**2004**
218	220	275	305	243

Source: 2005 TDRP: Appendix 1.

This data demonstrates that tree contacts have been trending higher the last three years. Furthermore, the Company notes that in 2004, vegetation contacts accounted for 10.6% of customer interruptions, vs. 9.9% over the years 2000-2003. Response to Interrogatory OCC-156. As the Department noted in its 2005 annual reliability report, tree/vegetation contacts are the second leading cause of outages in UI's system, next to equipment failure. Decision in Docket No. 05-05-05, p. 10. Given that the trend has been toward more tree/vegetation contacts and more customer outages from tree/vegetation contacts, the Department believes it is important that the Company respond by increasing its level of effort in preventing tree/vegetation contacts. Therefore, the Department supports the Company's effort in committing more resources to this effort.

***35** *b. Multiple Spot Trimming and Unit Spot Trimming*

These programs govern trimming and tree removal of trees at specific locations as a result of external customer requests and internal requests related to maintaining distribution lines. The 2004 expense for these activities totaled $135,000, and the proposed 2006 rate year expense is $259,000. The OCC states that the cost increase has not been justified, since the only Company justification for the expense is that the costs are estimated based on the historical costs. Therefore, the OCC states there is no justification for the proposed increase and that the costs should be based on escalated 2004 expenses, and recommended applying inflating costs by 1.75% per year through the term of the Rate Plan.

The proposed and the OCC-recommended expenses for these programs are as follows:

Spot Trimming Expense

($ in thousands)

	2006	2007	2008	2009				
	Unit	Mult.	Spot	Mult.	Spot	Mult.	Spot	Mult.
9p								
Proposed	114	145	118	150	122	155	126	161
9p								
OCC	50	90	51	92	51	93	52	95
9p								
Recommended								
Adjustment	(64)	(55)	(67)	(58)	(71)	(62)	(74)	(66)
9p								
Total	(119)	(125)	(133)	(140)				

Source: Schedule WP C-3.5; Schultz and DeRonne PFT, Exhibit L&A-1.

The Department agrees with the OCC. Although the Department views vegetation removal as a vital component of distribution reliability, the Company has not justified the increase; rather, it implies that it has only escalated 2004 costs. Schedule WP C-3.5; Response to Interrogatory OCC-156. However, the total costs of spot trimming have nearly doubled from 2004 to 2006, reflecting far more than simple escalation of historical costs. The Department believes the OCC's adjustment is, therefore, appropriate and adjusts expenses for these programs as indicated in the table above.

c. Vine Removal

In 2005, the Company instituted a new program to remove vines that threaten contact with electric wires. The Rate Plan assumes $124,000 in the rate year to fund one dedicated vine clearance crew, escalated in subsequent years. Schedule WP C-3.5. The AG and the OCC state that vine removal is a normal part of routine line maintenance, and there is no justification for the Company separating it into a new program and increasing the funding for it. AG Brief, pp. 22 and 23; OCC Brief, pp. 100 and 101. UI states that vine contacts have been an increasing problem on its distribution system for the last several years, and that it has established a program to more aggressively prevent vine contacts in response. Response to Interrogatory OCC-156.

***36** The need for the Company's vine clearing program was discussed extensively in the hearings. In 1998, UI revised its line clearing program to a performance based tree trimming interval, which was designed to reduce line clearance costs while maintaining reliability. As part of this change, the time-based tree trimming interval, which previously specified that each circuit be trimmed every four years, was changed to allow less frequent trimming based on a given circuit's tree contact history. Therefore, many circuits would be trimmed less often than once every four years. A side-effect of this change has apparently been that vines have been given more time to grow, causing the occurrence of more frequent vine contact outages in the Company's system. Tr. 10/11/05; pp. 703-709.

Previously, the Company has not had a line clearing program that specifically addressed vine removal. UI states that, beginning around 2003, it experienced several large-scale outages that originated from vines contacting electric lines. The Department believes that the above discussion on the history of vine contacts justifies that the Company needs to expend more effort to act more proactively in this area, and therefore approves the amounts budgeted to this effort.

d. Hazard Tree Removal Program

In 2005, UI instituted a new program to remove 'hazard trees', which are trees that are located outside the normal trim zone, and are dead, dying, diseased or structurally defective, and also present a potential hazard to electric distribution facilities. The Rate Plan assumes $207,000 in 2006 for this program. Response to Interrogatory OCC-156. The AG states that the Company has little evidence demonstrating that such trees have posed a reliability problem, and that removal of some hazard trees was already provided for by its previous line maintenance plan. AG Brief, p. 23. The OCC also states that hazard tree removal was part of prior programs, and recommends a small reduction to $199,000. OCC Brief, p. 102.

The Company states that it has instituted this program to improve reliability, since such trees represent a substantial threat to electric facilities. The Company further states that it has experienced several incidents in the past few years where trees outside the normal trim zone fell into electric facilities, causing significant outages. Although it has been done in the past, this program makes hazard tree removal a separate, more formal program and dedicates 1.5 crews to hazard tree removal. Tr. 10/11/05, pp. 657 and 658.

The Department will allow the expense for this program. It should be noted that this program resembles a CL&P program that is dedicated to removing 'hazard trees', which CL&P has found to be effective in improving reliability, and which the Department has reviewed and approved in other proceedings. Further, the funding for the program is moderate.

e. Planned Circuit-Mile Trimming

The Planned Circuit-Mile tree trimming program is UI's routine annual tree trimming program that is designed to maintain a clearance envelope around conductors. UI Spent $834,000 on this program in 2004. In 2006, 464 miles are planned to be trimmed at an assumed cost of $2,450 per mile, for a total expense of $1,242,000. The primary reason for the increase is the Company's expansion of the trim zone around wires in 2005, which increases the amount of vegetation that must be removed during routine trimming. Schedule WP C-3.5A.

***37** The OCC states that the approximately 40% increase is not justified, since the costs attributable to the trim zone expansion are difficult to quantify, and is not sufficiently justified by the Company. Therefore, the OCC recommends removing the incremental expense of the trim zone expansion. Schultz and DeRonne PFT, p. 56.

As discussed previously, the Company's reliability indices have decreased over the last six years, and its tree contact outages have recently increased. The Department believes this is likely related to the transition to performance-based tree trimming, discussed above, which, in many instances, allows more time for tree limbs to regrow into lines. Expansion of the trim zone should reduce tree limb regrowth into electric facilities, reducing the incidence of tree contacts, and will essentially ‘buy more time‘ until the next trim is required. Further, the cost of the expanded trim zone will likely be lower after each circuit receives its initial trimming under the new program, since subsequent trims will only remove regrowth. The Department believes the expanded trim zone is a desirable improvement to UI's vegetation management practices, and will allow expenses associated with the program.

f. Remaining Line Clearance

Remaining Line Clearance dollars include expenses associated with restoring from minor storms, tree related emergencies, and traffic control associated with all other line clearance programs. UI spent $510,000 on this program in 2004. The Rate Plan assumes $476,000 on this effort, escalated in subsequent years. Schedule WP C-3.5.

The OCC states that the Company did not provide any support for this item, therefore, it reduced its proposed allowance for it to $259,000 in 2006, escalated in subsequent years. OCC Reply Brief, p. 102.

The Department notes that the proposed expense for this activity is less than the 2004 test year. The account includes some activities that are not predictable, such as restoration from minor storms. Since the expense is less than the rate year, the Department believes the Rate Plan amount is reasonable and approves it.

4. Outside Services — Storm Reserve

In its Application, UI proposes additions to its Storm Reserve expense of $600,000 annually in years 2006 through 2009. Schedules C-3.7 A-D. The accumulated balance in the Storm Reserve Account at December 31, 2005, on a pro-forma basis, is $3.739 million. Schedule B-8.0 A. The cumulative balance in the reserve account at the end of the rate period, December 31, 2009, is expected to be $6.139 million. Schedule B-8.0 D.

UI uses Hurricane Gloria, which occurred in 1985, as a baseline of the potential costs associated with a ‘major event.‘ It is estimated that that hurricane would cost $8 million today. The Company states that if a comparable event were to occur during the rate period, the reserve would be fully utilized as it would fall below the amount needed. Response to Interrogatory EL-146. The actual expenses charged to the storm reserve were; $188,000 in 1999; $96,000 in 2000; $601,000 in 2001; $1,995,000 in 2002; and $0 in years 2003, 2004 and 2005 to date. *Id.*, p. 2; Tr. 10/11/05, p. 772.

***38** The OCC recommends that the annual storm reserve accrual of $600,000 be discontinued at this time because the historical average charge over the last six years (ending in 2004) is $480,000. At that level, the estimated reserve at December 31, 2005 of $3.7 million would be sufficient for at least seven years without any additional accrual to that total. By removing the storm reserve expense, the reserve amount in rate base should be reduced (increasing rate base) by $300,000 in 2006, $900,000 in 2007, $1,500,000 in 2008 and $2,100,000 in 2009. In addition, the deferred income tax asset for the reserve must also be reduced (decreasing rate base) by $123,000 in 2006, $367,000 in 2007, $611,000 in 2008 and $855,000 in 2009. OCC Brief, pp. 91 and 92.

The AG likewise recommends reducing or temporarily suspending UI's annual accrual into the storm reserve account. It states that reducing or temporarily suspending the amount of annual accrual, at the recent average rate of usage, will not eliminate the storm reserve. AG Brief, p. 25.

The Company discussed its current methodology of classifying what is, or is not, to be considered a major storm in accordance with Department directives and intent. Prior to 2003, charging the reserve account depended on the number of switching steps that the Company had to perform, rather than the extent of storm damage and the number of customers affected by the storm. In 2003 and 2004 (continuing into 2005), the Company made no charges to the storm reserve account because of its new definition of major storm being predicated on the extent of damage and the number of customers involved. Tr. 10/11/05, pp. 772-776. By inference, the Department notes that any and all storm damage expense that occurred in the period 2003 through 2005 must have been charged to either O&M expense or capitalized. In either event, these expenses are already included in test and rate year proposed expenses and capital items, and act as an adequate buffer against charges to the storm reserve.

The Department agrees with the OCC and the AG that the storm reserve balance at the end of 2005 of $3.7 million is sufficient to provide the Company protection against a potentially catastrophic event. The Department notes that since Hurricane Gloria, no catastrophic event occurred that required using $2 million or more in either expense or storm reserve during that 20-year period. *Id.*, p. 775. Also, if a catastrophe were to occur that exceeded the amount in the reserve account, the Company indicated that it would ‘clearly be back before the Department as quickly as we could to seek recovery.‘*Id.*, p. 778. If such a catastrophe occurs, the Department hereby allows the Company to create a regulatory asset immediately upon the occurrence of the event and payment of the storm-related related expense to be recovered, along with an amount to begin to restore the depleted reserve, in rates to be determined by the Department in a subsequent proceeding.

***39** The Department, therefore, agrees with the OCC and hereby disallows the storm reserve expense of $600,000 in each year 2006 through 2009. Further, the proposed reserve amount in rate base is reduced (increasing rate base) by $300,000 in 2006, $900,000 in 2007, $1,500,000 in 2008 and $2,100,000 in 2009. In addition, the proposed deferred income tax asset for the reserve is reduced (decreasing rate base) by $123,000 in 2006, $367,000 in 2007, $611,000 in 2008 and $855,000 in 2009. The Department will review the sufficiency of the storm reserve balance in UI's next rate case proceeding.

5. Outside Services — Environmental Costs

In its Application, UI reflected the test year actual environmental expense of $171,000. The Company then proposed expenses of $235,000, $303,000, $314,000 and $268,000 in years 2006, 2007, 2008 and 2009, respectively. Schedule C-3.8 A-D.

The OCC points out that a part of the environmental expense relates to the Skiff Street remediation which will be completed by the end of 2006. It indicates that the Company included $54,000 and $56,000 in years 2007 and 2008 for potential post-remediation groundwater monitoring which is an option of the Connecticut Department of Environmental Protection, but not a certainty at this point. Therefore, the OCC argues for those costs to be removed from rates. OCC Brief, p. 103.

Additionally, the OCC notes that increases of $62,000, $67,000 and $72,000 are projected by the Company in years 2007, 2008 and 2009, respectively, to have outside companies clean up oil spills from leaking transformers, dispose of used oil from leaking transformers and dispose of sludge removed from manholes and underground vaults. The OCC indicates that these increase amounts have not been justified or supported, and, therefore, should be removed from rates. *Id.*, pp. 103 and 104.

The Department agrees with the OCC that speculative, unjustified or unsupported amounts should not be included in rates. However, the Department has held in the past that the cost of environmental clean-ups is the ultimate responsibility of ratepayers. Accordingly, the Department disallows environmental expenses of: $116,000 in 2007 ($54,000 plus $62,000); $123,000 in year 2008 ($56,000 plus $67,000); and $72,000 in year 2009. However, the Department will allow the Company to defer amounts spent on required environmental projects, above what is approved in rates in this docket, that aggregate over $100,000 on an annual basis to be considered in its next rate case proceeding.

6. Outside Services — Technology Expense

In its Application, UI proposes Outside Services — Technology expenses of: $12.396 million in 2006; $11.790 million in 2007; $11.188 million in 2008; and $11.712 million in 2009. This compares to the test year 2004 actual cost of $7.563 million. Schedule C-3.11 A-D.

The OCC identified an increase from $125,000 in 2004 to $410,000, an increase of $285,000, in 2006 for IT support for client fulfillment required to meet Department requirements or changes, expansions of customer services, new legislation affecting services and other mandatory requirements based on the Company's forecast. An additional $300,000 increase was also included for IT support for ES (Electrical System) services required to meet the Company's forecasted changes as enumerated above. The OCC recommends that each of these unsupported increases be removed because it is not known for certain that additional legislation, mandates or Department requirements will be implemented in the future that will cause increased IT support costs above the level incorporated in the historic test year. Therefore, Technology expense should be reduced by $585,000 ($285,000 plus $300,000) in each of the rate years. This recommendation still allows for a significant projected level of increases in this cost category. OCC Brief, pp. 108 and 109.

***40** The Department agrees with the OCC that the additional IT expenses proposed by the Company are unsupported and speculative. Accordingly, the Department disallows $585,000 in each rate year 2006, 2007, 2008 and 2009, respectively.

7. Outside Services — Professional Services

The Company proposes rate period expense levels for professional services as: $4.162 million in 2006; $4.239 million in year 2007; $4.383 million in year 2008; and $4.507 in year 2009. This compares to test year 2004 actual expense of $2.668 million, and test year *pro forma* expense of $3.005 million (after reflecting the effects of a Sarbanes-Oxley initiative for $131,000 and other finance reorganization adjustments). Schedules and WPs C-3.14 A-D.

The OCC recommends five separate adjustments to the Company's requested level of Outside Services — Professional Services expense in the areas of: benchmarking; Broadband over Power Line pilot program; regulatory consulting (non-legal and non-rate case); long-term financing costs; and client services support. OCC Brief, p. 104.

a. Benchmarking Studies

In the area of benchmarking, the OCC points out that the Company has requested $143,000, $144,000, $145,000 and $147,000 in years 2006, 2007, 2008 and 2009, respectively. Year 2004 (test year) expense was $0. It notes that the Company stated that its proposed amounts were derived based on prior experience, and that $65,000 of the annual amounts was specific to Information Technology (IT) for Gartner benchmarking. However, the Company has not yet committed to the benchmarking studies, but it plans to undergo this benchmarking in the third quarter of 2006. The benchmarking studies will include studies in the areas of IT Electric System and UI's Program Management Center. As UI did not include support for how the increase in benchmarking costs were derived, and has yet to commit to the studies, the OCC recommends 50% of these costs be removed, reducing expenses by $72,000, $72,000, $73,000 and $74,000 in 2006, 2007, 2008 and 2009, respectively. *Id.*, pp. 105 and 106.

The Department concurs with the OCC's perspective in the area of benchmarking expense and also notes that the Company failed to adequately support its proposed expense in this area. The only benchmarking amount that was supported, even by explanation, was the Gartner study for $65,000 per year. Tr. 10/12/ 05, p. 1003. Therefore, the Department accepts the OCC's recommendation and disallows benchmarking expenses of $72,000, $72,000, $73,000 and $74,000 in 2006, 2007, 2008 and 2009, respectively.

b. Broadband over Power Lines

The OCC indicates that UI included $98,000 annually during the rate period for a broadband over power lines (BPL) pilot program to see if the technology works. It notes that the BPL project could result in cost savings that have not been reflected in the rate filing. Further, if successful, the BPL program could result in programs and revenues from third party providers, the profit from which would not be reflected above-the-line. Therefore, the Company is requesting full ratepayer funding for the BPL pilot program that could potentially result in unregulated revenues in the future, with none of the potential cost savings being reflected. Therefore, the OCC recommends disallowance of BPL pilot program expenses of $98,000 per year during the rate period. OCC Brief, p. 106.

***41** The Department notes that UI believes that there are utility operational benefits to BPL that will help the Company to better operate the distribution system, communications data, operating devices out in the field, etc. Beyond that, the Company would look for a third-party provider to cover the cost of, potentially, a $30 million system, $5 million of which can be justified by operational benefits. The Company currently has a wireless broadband solution deployed in Shelton to have some determination as to how BPL and wireless technology works. Tr. 10/12/05, pp. 1004-1008. Based on this Company testimony, it appears that the main thrust of the BPL project is to gain unregulated revenue from the use of regulated utility assets, with only the potential of 16.7% ($5 million divided by $30 million) of BPL potentially being used on the regulated utility side. If the $5 million were invested and deployed, the OCC opines that cost savings/operational efficiencies would result that have not been reflected in this rate case. The Department hereby agrees with the OCC that BPL pilot program expense is not primarily directed to the provision of delivering electric power to ratepayers, and, therefore, disallows $98,000 in each of 2006, 2007, 2008 and 2009, respectively.

c. Regulatory Consulting

The OCC indicates that UI is requesting $181,000, $188,000, $195,000 and $202,000 for outside professional services — regulatory compliance (non-legal, non-rate case) for years 2006, 2007, 2008 and 2009. UI's historical expense in this area has been $10,000 in the test year 2004, and a three-year (2002-2004) average of $16,000. Again, the OCC indicates that the Company has not supported the proposed increases which were, purportedly, based on historical experience. Tr. 10/12/05, pp. 1011-1013. Therefore, the OCC recommends reductions to this expense of $165,000, $172,000, $179,000 and $186,000 in years 2006, 2007, 2008 and 2009, respectively. OCC Brief, pp. 106 and 107.

The Department agrees with the OCC that the historical pattern of expense for regulatory consulting does not support the Company's proposed amounts. However, the Department is sensitive to increased non-rate case regulatory activity mandated by recent legislative action (and the potential for such activities in the future) that could cause an increase in the Company's use of outside professional services for regulatory compliance in non-rate case dockets. However, the Department finds that UI's proposed expenses are extravagant. Therefore, the Department allows a level of $50,000 per year, or roughly three times the historical average, for outside professional services for regulatory compliance (non-legal, non-rate case). Accordingly, the Department reduces UI's expense proposal in this area by $131,000, $138,000, $145,000 and $152,000 in years 2006, 2007, 2008 and 2009, respectively.

d. Long-Term Financing Costs

The OCC states that UI's Application increases the test year 2004 level of outside services for long-term financing costs from $226,000 to $420,000 for each year in the four-year rate period. These costs represent bond insurance fees, trustee fees, auction agent fees and broker/dealer fees related to UI financings. The Company is requesting that ratepayers be required to pay for the fees resulting from Moody's downgrading. It is the OCC's position that ratepayers should not be responsible for these, downgrade-resulting, projected higher outside service financing costs, and recommends that each rate year amount be reduced by $194,000 to reflect the actual 2004 level of $226,000. OCC Brief, pp. 107 and 108.

***42** The Department notes that bond insurance fees, trustee fees, auction agent fees and broker/dealer fees are related to UI financings previously made. Response to Interrogatory OCC-161, p. 4. Subsequently, the Company explained that these costs are annual and ongoing and referred to its response to Interrogatory EL-1, in Docket No. 03-07-08, *Application of The United Illuminating Company for the Approval of the Issuance of Debt Securities and the Refunding of Borrowings*, where ongoing costs were described as ‘annual expenses for fees paid to the auction agent (2 basis points) and the broker/dealer (25 basis points) and for bond insurance (7.5 basis points).‘ UI also provided details of the ongoing costs by issue and agent and stated that these annual fees for long-term financings cannot be capitalized at issuance, and are appropriately accounted for as an annual O&M cost. A specific example of ongoing costs is the broker/dealer fees paid to Morgan Stanley on BFA 2003 Series bonds, $64.5 million, sold at auction held every 35 days. UI Written Exceptions, pp. 37 and 38.

The Department hereby finds that the Company's Long-Term Financing Costs are annual periodic payments that were not capitalized as initial issuance costs, and allows UI's proposed annual expense of $420,000 in each year during the four-year Rate Plan.

e. Client Services Support

The OCC indicates that the Company is projecting an increase in outside professional services — client services support from the test year 2004 level of $147,000 to $422,000, $443,000, $458,000 and $476,000 in years 2006, 2007, 2008 and 2009. The majority of these costs are for strategic project implementation efforts and the use of outside consultants for new products and new services development investigation. Further, the OCC indicates that the Company has not justified or supported the projected 200% increase in this area. The OCC recommends that these costs be held at the 2004 level of $147,000, and that the projected expenses should be reduced by $275,000, $296,000, $311,000 and $329,000 in years 2006, 2007, 2008 and 2009, respectively.

The Company explained that the increase of $275,000 from 2004 to 2006 represents: $89,000 for customer area IT support, $138,000 for financing local and regional economic development (ED) organizations' projects; $31,000 for customer sales and new ventures; and $17,000 for consulting support for customer service and process based initiatives. Late-Filed Exhibit No. 40. The Department notes that no specific new products, customer services or ED organizations' projects were identified by the Company in the Company's descriptions supporting the expenditures. Also, UI consistently referred to ‘various‘ projects and efforts throughout the discovery process. *Id.*; Tr. 10/12/05, p. 1021. Without the Company providing any specificity as to new customer products, services or ED projects, the Department is not inclined to allow large expense increases in this category, and, therefore, agrees with the OCC's recommendation. Accordingly, outside services — client services support expense is allowed at the 2004 rate year expense level of $147,000, and hereby reduced by $275,000, $296,000, $311,000 and $329,000 in years 2006, 2007, 2008 and 2009, respectively.

f. Professional Services Summary

***43** In the five areas of professional service aforementioned, the Department made the following outside service expense disallowances:

Description	**2006**	**2007**	**2008**	**2009**
Benchmarking studies	$72,000	$72,000	$73,000	$74,000
BPL	$98,000	$98,000	$98,000	$98,000
Regulatory consulting	$131,000	$138,000	$145,000	$152,000
Client services support	$275,000	$296,000	$311,000	$329,000
	——	——	——	——
Total professional services expense disallowed	$576,000	$604,000	$627,000	$653,000

8. Outside Services — Audit and Accounting Expense

UI originally projected $533,000, $552,000, $573,000 and $594,000 for audit and accounting expense for rate years 2006 through 2009, respectively. Schedule C-3.16 A-D. UI later increased the projected expenses by $149,000, $164,000, $177,000 and $194,000 for rate years 2006 through 2009, respectively, citing the Company's response to Interrogatory EL-159. Late Filed Exhibit No. 1, Revised.

However, the response to Interrogatory EL-159 only identified a potential increase of $100,000 for 2006. The Company's response to Interrogatory EL-159 and the testimony on 10/14/05 state that the original projection was strictly an estimate and that UI is in negotiations with Pricewaterhouse Coopers for a new contract. UI is seeking to enter into a long term fixed price contract for SEC reporting audit services to mitigate the potential increase. UI testified that the Company is still negotiating and trying to get the price increase down, but, the increase could be greater than the original estimate. Response to Interrogatory EL-159; Tr. 10/14/05, pp. 174 and 175. UI later testified that they negotiated a new contract and the increases in Late Filed Exhibit No. 1 are based on the cost of the new contract. Tr. 11/9/05, p. 2394.

The OCC believes that the response to Interrogatory EL-159 does not support the amount of increase apparently requested by UI in Late Filed Exhibit No. 1 and leaves unanswered questions regarding the certainty of the projected increases. Therefore, the OCC has removed the increases identified in Late Filed Exhibit No. 1. OCC Brief, pp. 63 and 64, Exhibit 5.

The Department takes into account the entire record evidence on a given expense in determining if it is proper for the rate year. Therefore, based on the testimony given during the late filed exhibit hearing, the Department approves the increase to accounting and audit expense as shown in Late Filed Exhibit No. 1, Revised.

***44** *9. Directors and Officers Liability Insurance*

The Company proposes expenses for Directors and Officers Liability Insurance (DOL) of $533,879 for 2006, and $559,612 for each of the years 2007 through 2009. Response to Interrogatory OCC-104. UI contends that it could not attract a director if it didn't have DOL. It is a cost of doing business. Tr. 10/ 12/05, p. 868. Further, the Company asserts that, taken to the extreme, ‘if there was no insurance and there was a huge claim, it could put the company in financial peril, which would potentially impair its ability to serve.‘ Tr. 10/ 11/05, p. 801.

The OCC indicates that ‘the numerous corporate scandals since 2001 has caused the cost of the DOL insurance to skyrocket.‘ Schultz and DeRonne PFT, p. 48. Further, ‘DOL insurance provides shareholders protection from their decision. Ratepayers in general do not elect the Board of Directors and do not appoint officers to run the Company. Shareholders are protected by this insurance against their own decision in the selection of management. Ratepayers should not pay for the cost of insurance designed to protect shareholders from their own decisions.‘ OCC Brief, p. 93; Tr. 10/12/05, pp. 867 and 868. Therefore, the OCC recommends that all of the DOL amounts during the rate period be excluded from rates and be covered completely by shareholders, not ratepayers.

The AG agrees with the OCC's reasoning that DOL insurance protects only shareholders from the actions of management that they selected. Thus, DOL insurance expense should be eliminated from UI's rates entirely. AG Brief, pp. 24 and 25.

The Department partially agrees with the OCC, the AG and the Company. In the 03-07-02 Decision, the Department allowed a *portion* of that company's proposed expense and stated that ‘the Department has historically allowed some level of expense for D&O Insurance in rates to assure some level of ratepayer protection from catastrophic lawsuits.‘ 03-07-02 Decision, p. 49. The Department also notes that the annual gross DOL premium (before credits and allocations) was $134, 430 in years 2001 and 2002, increasing to $1,029,516 in years 2007 through 2009, lending credence to the OCC's assertion regarding corporate scandals, above. The Department agrees with the OCC that the shareholders should bear the weight of their decisions in appointing directors (who appoint the officers of the Company). Accordingly, the Department allows $140,000 of DOL expense, or approximately 1/4 of the total company expense, to be collected in rates as the customers' responsibility.

The Department, therefore, disallows DOL expenses of $393,879 in 2006, and $419,612 in each of 2007, 2008 and 2009.

10. Postage Expense

UI projected postage expense in the amounts of $1,475,000, $1,479,000, $1,485,000, and $1,491,000 for rate years 2006 though 2009, respectively. UI increased the test year expense of $1,361,000 by $74,000 for an anticipated 5.4% increase from the USPS and $31,000 for volume and usage increase. Schedule C-3.20 A — D.

***45** The Governors of the U.S. Postal Service have accepted the recommendation to increase most postal rates and fees by 5.4% effective January 8, 2006, including an increase in the rate for first-class mail from 37 cents to 39 cents. *See* http://www.usps.com/ratecase/welcome.htm.

UI states that the volume and usage increase is due to items such as increase in collection letters due to higher disconnect for nonpayment activity, new program mailings and increased economic development activity. Response to Interrogatory EL-220.

The OCC states that at this time it is uncertain whether the 5.4% proposed USPS rate increase will actually occur and when the new rates would be implemented. The 5.4% increase in postage rates is speculative and ratepayers should not be expected to pay for an expense that is not known and measurable. To the best of the OCC's knowledge, the postal rate increase docket is still open. In addition, the Company's volume and usage increase to postage expense is not the result of an increase in the number of bills due to customer growth, but rather an increase in mailings for collection letters, special messages, special mailings, new program mailings and economic development activity mailings. Therefore, the OCC recommends that this amount be removed. OCC Brief, p. 96.

The OCC recommends postage expense be reduced by $105,000 in rate year 2006, $109,000 in 2007, $115,000 in 2008 and $121,000 in 2009 to remove the speculative postal rate increase and the cost included for increases in mailings. OCC Brief, p. 97.

The Department reviewed the USPS website and determines that the requested rate increased was approved effective January 8, 2006. The Department believes that the increased mailings for collections and new programs are reasonable. Therefore, the Department approves the 2006-2009 postage expense as proposed by UI.

11. Sublease Income

UI currently subleases space to a tenant in its Connecticut Financial Center (CFC) building in New Haven. UI originally projected $338,000 in sublease income in 2006 and $0 for 2007-2009, stating that the current lease expires in 2006 and market conditions for New Haven are adverse. The sublease income for 2004 was $380,000. Schedule WP C-3.21 A-D.

During the proceeding, UI was in negotiations with the subtenant and believed that they would come to terms on a new lease agreement. UI received a verbal okay from the broker for the tenant regarding the new lease. UI estimates new sublease income of $138,000 (reflecting discounts) in 2006 and $166,000 in 2007-2009. The projected sublease amounts are reflected in the Company's Second Revised Late Filed Exhibit No. 1. In addition, UI has hired a broker to look into opportunities to sublease out the additional approximately 5,000 square feet of space that will not be occupied in the new lease. Currently UI does not have specific plans for the unused space and has not included any sublease revenues in its Second Revised Late Filed Exhibit No. 1. Late Filed Exhibit No. 28; Tr. 11/9/05, pp. 2391, 2392 and 2428.

***46** Nicholas indicated that the CFC is one of the '…premier buildings in the city in terms of location.' He also indicated that if the Company vacates the CFC as part of the Central Facility plan, he '…would imagine the floors would fill up again pretty quickly with new tenants and add jobs with that. ' Tr. 10/14/05, pp. 1252 and 1253. Based on this testimony regarding the desirability of the location and the fact the space is in a premier building in the city, it is even more unclear why the Company first anticipated $0 sublease revenue in this 'premier' building, then updated that amount to still reflect a significant drop in the amount of sublease revenue it is currently receiving. OCC Brief, p. 92.

The OCC recommends that the sublease income be set at $416,000 in 2006, $429,000 in 2007, $442,000 in 2008 and $455,000 in 2009. This amount is based on the actual 2004 sublease income inflated for each year based on the projected increase in cost per square foot in the facility for UI's affiliates. This would increase the sublease income amounts contained in UI's initial filing by $78,000 in 2006, $429,000 in 2007, $442,000 in 2008 and $455,000 for 2009. Schultz and DeRonne PFT, p. 49, Exhibit__ (L&A-1), Schedule C-10; OCC Brief, pp. 92 and 93.

Regarding the space that UI has negotiated a new lease for, the Department believes the appropriate amount to include in revenue requirements is the actual amount that UI will receive under the terms of the new lease. Therefore, the Department accepts UI's new estimate of sublease income of $138,000 in 2006 and $166,000 in 2007-2009.

However, the Department believes that UI should not pass along costs to ratepayers for space that is not used and useful in the provision of utility service. If UI owned the 5,000 square feet of office space it would reclassify the property to the account for property held for future use where it would be removed from ratebase and the associated expenses would not be included in rates. In the alternative, UI could rent the space and receive rental income to offset the expenses. In this proceeding UI has not included either option in its revenue requirement.

The Department agrees with the OCC that there is a high probability that UI could rent the additional space for a premium rent given the testimony that the CFC is a premier building in New Haven and desirable office space. However, the Department does not know the exact amount of rent that could be received. What the Department does know is the amount that UI charges its affiliates to rent space in CFC. The Department assumes this is a fair market rent and not a special deal given to its affiliates. Therefore, the Department uses the cost/square foot allocation of $41.17, $45.11, $46.47 and $49.30 for the years 2006-2009, respectively, in calculation of imputed sublease income for the 5,000 square feet of available space. The additional sublease income is $206,000, $226,000, $232,000 and $247,000 for the years 2006-2009, respectively.

12. Telecommunications Expense

***47** UI projected $1,896,000, $1,924,000, $1,978,000 and $2,009,000 for telecommunications expense for rate years 2006 through 2009, respectively. Test year, 2004, telecommunications expense was $1,458,000. Schedule C-3.22 A-D.

Since 2002, the annual telecommunications expense has declined from a high of $1,802,000. Response to Interrogatory EL-260. However, 2006 includes costs for new telecommunications systems such as $200,000 for an additional circuit for a secondary connection from the General Packet Radio Service (GPRS). The GPRS replaced the discontinued Cellular Digital Packet Data communication package for the Company's vehicles. UI also increased the costs for the company wide phone system by $74,000 for the implementation of voice over internet protocol (VOIP) system. Smaller increases identified include general inflation and $20,000 in 2008 for a new cellular phone contract that has yet to be negotiated. Response to Interrogatories EL-259 and OCC-168. The Company testified that it conducted a cost benefit analysis regarding the implementation of VOIP system. Tr. 10/14/05, pp. 1086 and 1087.

The OCC cited concerns that UI did not provide calculations for the increased telecommunications costs in response to Interrogatory EL-259. Specify, the OCC asked the Company about the lack of calculations during the hearing on 10/15/05 at which time the Company witness indicated that the response lists the projects and the explanations, but does not provide the calculations requested and does not provide how the amounts were derived. Tr. 10/14/05, pp. 1081 and 1082.; OCC Brief, p. 109.

Considering annual declines in telecommunications expense that have occurred since 2002, and the lack of supporting detail, calculations and assumptions provided by the Company in support of the projected telecommunications expense increase, the OCC recommends that telecommunications expense continue at the 2004 level of $1,458,000. This does not continue the annual decline that has occurred since 2002, but will continue the actual 2004 cost level in rates. It also would not reduce the costs for the savings that may occur as a result of the 2006 VOIP implementation. Therefore, the OCC recommends that telecommunications expense be reduced by $438,000 in 2006, $466,000 in 2007, $520,000 in 2008, and $551,000 in 2009. OCC Brief, p. 110.

UI identified specific line items within telecommunications expense that are going to be higher in the rate year then they were in the test year. The OCC appears to ignore those explanations in its recommendation to hold Rate Plan telecommunications expense at the test year amount. The OCC also cites Company testimony that calculations were not provided in response to Interrogatory EL-259. The Department reviewed the entire testimony on the issue of supporting calculations and found that the only follow up that the OCC requested was for the budget data for the Company-wide phone system, which was provided in Late Filed Exhibit No. 43. *See* Tr. 10/14/05, pp. 1082-1085.

***48** In general, the Department believes that UI identified major increases in its telecommunications costs. However, the Department reviewed the historical amounts provided in response to Interrogatory EL-260 and did not find general annual increases for inflation. Various items increased and decreased by different amounts each year. The Department believes it is appropriate to make a modest decrease of $50,000 in annual telecommunications expense for each year 2006-2009 to remove the effects of general inflation. In addition, the Department removes the 2008 increase for the potential increase in cellular phone costs since the contract has yet to be negotiated. Therefore, the Department decreases telecommunications expense by $50,000 in 2006 and 2007 and $70,000 in 2008 and 2009.

13. Travel, Education and Training Expense

In its Application, the Company proposes Travel, Education and Training expenses of $2.336 million, $2.441 million, $2.468 million and $2.524 million in 2006, 2007, 2008 and 2009, respectively. Schedule C-3.26 A-D. UI's budgeted training programs, aside from its tuition assistance program, are broken up into two major groupings: job skills and technical/operational training; and management and professional development. The job skills training budget includes training programs for areas such as power delivery, transmission and substation, client relations, standard field training and customer operations. The technical/operational training programs include education and training for UI's varied technology systems, infrastructure operation and maintenance and energy technology operations. Management and professional development training includes leadership, supervisory and executive development programs, participation in industry and professional conferences and committee work and project management and process improvement training. Revised response to Interrogatory EL-173. The Company indicates that its proposed 140% increase in training dollars reflects both self-imposed, non-representative historical cost constraints in past years and the need to train the significant amount of new employees that are being hired to replace its aging workforce. Tr. 10/11/05, pp. 788-791.

The OCC states that a 140% training expense increase over the Company's historic level is not justified, not appropriate and unsupported. It states that in 2004, training for management skills, leadership, supervisory development, executive development and other training did occur. The OCC recommends applying a 5% increase to the 2004 test year training expense base, and recommended reductions to UI's proposed training expense ranging from $1.4 to $1.5 million annually during the rate period. OCC Brief, pp. 89 and 90.

The Department is also concerned that the substantial increase proposed by the Company has not been adequately supported, in detail, in dollars per individual program or by the number of employees, by job description, which are proposed to require training. Further, analyses of the Company's historical information, despite UI's claims of expense constraints, does provide insight as to the magnitude of the increase requested. For example, for the five years ended 2005, UI averaged $1.035 million per year for training expense on an average Full-Time Equivalent (FTE) employee count of 828. This calculates to $1.25 per FTE for training during the most recent five-year period. The average for the four-year rate period is $2.443 million per year for 934 FTEs, or $2.62 per FTE for employee training. This equates to a *236%* increase ($2.443 divided by $1.035) proposed for the rate period above historical levels. Source Late Filed Exhibit No. 27 with Attachment; Late Filed Exhibit No. 11 (FTEs). The Department is not convinced that this significant increase is justifiable or warranted.

***49** The Department recognizes that new employees must be trained, and that all training is ongoing. However, the Department is unconvinced that $1.5 to $1.6 million per year is necessary for management and professional development, or that $.7 to $1.0 million per year is necessary for job skills and technical operational training. Therefore, the Department will adjust training expense by increasing the five-year historical average of $1.25 per FTE by approximately 40% to reflect a factor for the Company's self-imposed constraints and to recognize the additional training requirements for replacement new hires going forward. Therefore, the Department will allow a rate of $1.75 per FTE in 2006, and escalate this amount for cost increases by 4% annually thereafter. This calculates to allowed training expenses of: $1.605 million in 2006 (917 FTEs times $1.75); $1.700 million in 2007 (934 FTEs times $1.82); $1.777 million in 2008 (940 FTEs times $1.89); and $1.862 million in 2009 (945 FTEs times $1.97).

Accordingly, the Department disallows training expenses of: $731,000 in 2006 ($2.336 million less $1.605 million); $741,000 in 2007 ($2.441 million less $1.700 million); $691,000 in 2008 ($2.468 million less $1.777 million); and $662,000 in 2009 ($2.524 million less $1.862 million).

14. Compensation Expense

a. New Hires to Replace Retiring Electric System Workers

UI plans to hire incremental Electric System[5] workers in anticipation of the future retirement of workers who are or will be eligible for retirement in the next several years. The Company states that the Electric System employees require long lead times to be fully qualified, typically approximately four years. To meet the projected decline in its Electric System workforce, the Company has initiated a recruitment and training program to fill an incremental 18 FTEs. The Company states that the targeted recruitment levels are based on retirement eligibility and anticipated attrition levels as well as lead times to develop the necessary skills in new workers. The net increase attributable to this program is $423,000 in 2006, $404,000 in 2007, $175,000 in 2008, and a small decrease in 2009. Reed PFT, p. 15; Response to Interrogatory EL-269.

UI states that the pending retirements are due to the maturing of the large population of workers UI hired in the 1960s and 1970s, when its infrastructure was in a rapid state of development. In 2004, the Company conducted a study of the resource needs to address attrition in the skilled technical positions, including lineworkers. Response to Interrogatory EL-271. According to the study, out of 393 total employees, the number of retirement-eligible employees will increase from 109 in 2005 to 163 in 2009. Up to five years of training is required for inexperienced new hires to replace fully qualified personnel, particularly among lineworkers, substation electricians, and underground system workers. These employees must go through a training/certification program which ranges in length from 3-5 years before the employees are fully qualified. Therefore, UI plans to hire personnel in advance of the retirements so that their replacements will be fully capable to assume duties. Response to Interrogatory EL-270.

***50** The OCC recommends that the Department allow the Company no more than 34 total incremental positions, including some to compensate for anticipated retirements of technical workers. However, the OCC did not provide specific recommendations regarding the levels of lineworkers and other Electric System workers that should be allowed. OCC Brief, p. 77.

The Company's study assumes that 33% of eligible employees will retire in their year of eligibility. Response to Interrogatory EL-271, Attachment EL-271-1. Over the last four years, 34% percent of eligible employees in the Electric System retired each year, compared to a companywide retirement rate of 12%. Responses to Interrogatories EL-274 and EL-385. The Company states that the differential in retirement rates is due to the physically demanding nature and stressful nature of their work. Tr. 10/7/05, pp. 500 and 501. The Department concludes that the evidence supports the supposition of a high retirement rate for Electric System employees; and, for the purpose of the Company's study, a 33% retirement rate is reasonable.

The Department addressed the issue of pending retirements of lineworkers for The Connecticut Light and Power Company (CL&P) in the 03-07-02 Decision. In that Decision, the Department acknowledged an aging lineworker work force and authorized CL&P to hire incremental lineworkers in anticipation of retirements. Further, the entry of large proportions of skilled technical workers into retirement age has become a concern throughout the energy industry. Decision, pp. 90-92.

The pending retirement of Electric System workers is a serious concern for UI. In 2005, 109 of the workers are eligible for retirement, which equates to 31% of all lineworkers. By 2009, if there are no hires, that number rises to 41%. The Department agrees that the pending retirement of Electric System workers is a concern that must be addressed. Line work is physically difficult, demanding work, often in harsh weather conditions and is not generally appealing to older workers, and it can reasonably be expected that a large percentage of eligible workers would retire soon after eligibility. Further, such work is critical to the reliability of the electric system. A shortfall in Electric System staffing would potentially affect the Company's electric system reliability, especially after restoring from a major storm.

The Department agrees with the Company's retirement forecast for planning purposes. The Company's expectations for hiring and attrition, given the above planning assumptions, are as follows:

Electric System Division Staffing

2005-2009

	2005	2006	2007	2008	2009	Total
Hires	27	26	22	22	22	119
Attrition	(25)	(21)	(19)	(18)	(18)	(101)
Net	2	5	3	4	4	18

***51** Source: Response to Interrogatory EL-269

The Department believes that the Company should proceed with the hiring of new Electric System workers as it has proposed, to avoid a future adverse impact on customer service by a shortage of Electric System workers. The Department views its approval of expense for this Initiative as a compact between the Department and the Company to carry out the forecasted level of hiring, and will order the Company to report to the Department annually on the actual level of hiring.

b. Incentive Compensation

UI has three incentive compensation plans, Management Compensation Program (MCP), Executive Incentive Compensation Program (EICP) and Executive Long-Term Incentive Program (LTIP). At year end (or end of the period for long-term goals), awards are determined by the results of the goals. The MCP consists of corporate, division, and team/individual goal results, while the EICP consists of financial goals and the UI and division scorecards. The LTIP is a performance share program and consists of the average of the earned return achieved each year of the three year program. Incentive Compensation costs are budgeted assuming achievement at the target level on a Company-wide basis each year. Response to Interrogatory EL-165. The MCP applies to 484 non-union employees in UI's leadership, professional, administrative and technical positions. The EICP and LTIP apply to 12 executives and managers. Tr. 10/07/05, pp. 480-482.

UI testified that the Company pays close attention to the development of specific incentive compensation goals to be sure that the goals are appropriate for the Company and employee. The objective is to motivate employees to achieve specific outcomes that support successful outcomes for the Company. UI believes that the 'pay at risk' incentive compensation plans compensate the Company's employees at market level. Response to Interrogatory OCC-97; OCC Brief, p. 47.

For the 2004 test year, UI's Incentive Compensation totaled $5,429,000. The Incentive Compensation currently allowed in rates is $3,539,000. Attachment EL-164-3; 01-10-10 Decision, p. 61.

The company has proposed the following for the rate years:

Year	Amount Proposed	% Change
2006	$5,649,000	4.1% *
2007	$5,919,000	4.8%

2008	$6,183,000	4.5%
2009	$6,418,000	3.8%

*Over test year level.

Source: Schedule WPC-3.27; response to Interrogatory EL-164-3.

As indicated above, UI's proposed incentive compensation is escalating at a rate of 3.8% to 4.8% per year.

Historically, the Company's actual Incentive Compensation expense has been as follows:

5p

Year	Dollars	% Change
2000	$4,661,000	n/a
2001	$4,381,000	-6.0%
2002	$3,789,000	-13.5%
2003	$2,765,000	-27.0%
2004	$5,429,000	96.3%
2005	$5,072,000	-6.6%
2005 (ytd actuals)	$3,671,000	n/a

***52** Source: Response to Interrogatories EL-348, EL-354 and Schedule WPC-3.27.

As indicated above, UI's incentive compensation payments vary significantly based on achieved goals.

The AG recommends that the Department deny UI's proposal to escalate its incentive compensation expense as a result of the Company not adequately justifying and providing adequate documentation to support the increase. AG Brief, p. 20.

The OCC states that certain assumptions could not be verified because no documentation or calculations were provided which illustrate that the pay is actually at risk and that there is a benefit that results from the performance at or above previously achieved levels of performance. The OCC believes that it is not appropriate for a regulated utility to request ratepayers to pay in excess of $5 million for incentive compensation as a reward to employees for achieving goals that they have not divulged to their regulators when requested and/or did not provide a response in a timely manner. Therefore, the OCC recommends disallowing the Company's Incentive Compensation in it's entirely. OCC Brief, p. 81. If the Department believes the total disallowance is too punitive, the OCC would then recommend that at a minimum the Department should disallow 50% of the incentive compensation requested because of the Company's failure to provide sufficient supporting documentation. OCC Reply Brief, p. 17.

The Company's three-year average for 2002-2004 totals $3,994,000. UI's 2006 through 2009 proposed incentive compensation amounts represent an increase of 41%-61% over the three year average. The Department finds the average appropriate because it includes UI's highest and lowest annual incentive compensation payments since 2000. Moreover, historical experience indicates that UI's incentive compensation payments vary significantly based on achieved results. Additionally, if the Department allowed the 50/50 sharing between ratepayers and shareholders, the Company would be allowed $2,825,000 in 2006. Utilizing the three year average, the Company is allowed 41.4% more than the 50/50 ratepayer/shareholder sharing.

In UI's written exceptions, the Company states that ‘freezing‘ the incentive compensation at $3,994,000 throughout the rate plan does not take into account any escalation of base salaries, which form the basis for the calculation of incentive compensation or the increasing FTE level. UI Written Exceptions, p. 8.

The Department believes that shareholders benefit from incentive compensation plans and it is appropriate that shareholders contribute if expenditures exceed the $3,994,000. The Department finds UI's escalation of incentive compensation expense excessive. Therefore, the Department will allow the three year average of $3,994,000 and reduces the Company's request by $1,655,000 in 2006, $1,925,000, $2,189,000 in 2008, and $2,424,000 in 2009.

c. UIL Allocated Incentive Compensation

In Schedule WPC-3.32, Corporate Service Charges, UI identified a number of UIL allocated Incentive Compensation items that total $4,949,000 for rate years 2006-2009. The Company is proposing the following for the rate years:

2006	$1,374,000
2007	$971,000
2008	$1,291,000
2009	$1,313,000
5p	
Total	$4,949,000

***53** Source: Late Filed Exhibit No. 14 and Schedule WPC-3.32

As indicated in the Incentive Compensation Section, the Department believes that shareholders benefit from incentive compensation plans and that it's appropriate for shareholders to contribute to these expenses. Therefore, the Department will allow the same percentages allowed in the UI Incentive Compensation Section. These percents range from 70.7% in 2006 to 62.23% in 2009 and were calculated by dividing amount allowed by the amount requested. Therefore, the Department will allow a UIL Allocated Incentive Compensation Expense equal to $971,456 in 2006, $655,208 in 2007, $833,940 in 2008, and $817,096 in 2009.

d. Capitalized Overhead

For test year 2004, UI's capitalized overhead totaled $2,682,000. The Company has proposed the following for the rate years:

Year	Amount Requested	% Change
5p		
2006	$1,996,000	-25.6%*
2007	$1,805,000	-9.6%

2008	$1,808,000	0.2%
2009	$1,808,000	0.0%

*Over test year level.

Source: Schedule WPC-3.27.

Historically, the Company's capitalized overhead have been as follows:

Year	Dollars	% Change
2000	$1,861,000	n/a
2001	$2,195,000	17.9%
2002	$2,317,000	5.6%
2003	$2,289,000	-1.2%
2004	$2,682,000	17.2%
2005	$2,339,000	-12.8%
2005 (ytd actuals).	$1,946,000	n/a

Source: Response to Interrogatories EL-348, EL-354 and Schedule WPC-3.27.

As indicated above, the Company's historical capitalized overhead varies. However, the Department notes that 5 out 6 years have been above $2,195,000.

The OCC states that the Company's capitalized dollars are decreasing from the test year levels, which is contrary to what would be expected with the addition of capital intensive employees and payroll escalation. The OCC believes that the Company's prefiled testimony, schedules and/or workpapers, or its response to data requests do not support the requested amounts and that the capitalized overhead portion is understated. The Company provided no detail on its calculation. The OCC recommends a test year capitalization rate of 5.75% which is consistent and based on a historic period. This is more reasonable than an unexplained declining amount purported to be based on historical data.

***54** The Department agrees with the OCC and finds that UI's capitalized overhead is understated. The Company's year to date capitalized overhead as of August 31, 2005 was $1,946,000. This amount annualized is $2,919,000. This amount appears to be more realistic than the Company's rate year projections. Specifically, considering the Company's compensation escalation and additional FTEs. The Department finds that it is appropriate to use the most recent actual experience and will average the past three years (2002-2004). Therefore, the Department will increase the Company's 2006 to 2009 capitalized overhead to $2,429,000 ($2,682,000 + $2,289,000 + $2,317,000)/3)). Thereby, decreasing compensation expense by $433,000 in 2006, $624,000 in 2007, $621,000 in 2008 and 2009.

e. Overtime and Premium Payroll

For test year 2004, UI's overtime and premium payroll totaled $5,399,000. The company proposed the following for the rate years:

Year	Amount Proposed	% Change
2006	$4,976,000	-7.8%*
2007	$5,133,000	3.2%
2008	$5,272,000	2.7%
2009	$5,494,000	4.2%

*Over test year level.

Source: Schedule WPC-3.27.

With the exception of the Company's 2006 decrease over the test year level, UI's proposed increase in overtime and premium payroll is projected to increase at a fairly consistent rate.

Historically, the Company's overtime and premium payroll have been as follows:

Year	**Dollars**	**% Change**
2000	$3,418,000	n/a
2001	$3,674,000	7.9%
2002	$5,647,000	53.7%
2003	$5,149,000	-8.8%
2004	$5,399,000	4.9%
2005	$4,826,000	-10.6%
2005 (ytd actuals)	$4,090,000	n/a

Source: Response to Interrogatories EL-348, EL-354 and Schedule WPC-3.27.

As indicated above, overtime and premium payroll have increased significantly since 2001. As of August 31, 2005, the Company has already incurred $4,090,000 in overtime and premium payroll. This amount annualized totals $6,135,000. Response to Interrogatory EL-354-1.

UI testified that the projected decrease in overtime is the combination of increases in employee levels from the Company's 2003-2005 line school and the Company's union contract includes some productivity improvements. Tr. 10/07/05, pp. 507 and 508.

The OCC is concerned with the Company's overtime projection. Again, the OCC states that the documentation and calculation was not provided. The OCC did not recommend an adjustment because the overtime and premium compensation is projected to be less than the test year and no adjustments are recommended at this time. OCC Brief, p. 78.

***55** The Department believes that the Company's overtime and premium payroll should decrease as a result of additional FTE's. However, based on evidence regarding retirements, a majority of electric system employees will be doubled up and productivity may decline. Tr. 10/07/05, pp. 513 and 522. Based on the Department's analysis for incentive compensation, capitalized overhead and the 2005 annualized amount of $6,135,000, the Department finds that it is appropriate to increase overtime and premium payroll accordingly. Therefore, the Department will allow a level of overtime and premium payroll equal to the average of the past three years (2002-2004). The Department finds that it is appropriate to allow $5,398,000 per rate year. Based on this analysis, the Department will allow an additional $422,000 in 2006, $265,000 in 2007, $126,000 increase in 2008, and a $96,000 decrease in 2009.

f. Net Compensation Expense

UI's 2004 test year distribution compensation expense for 616.1 FTEs totaled $46,817,000. The Company's proposed 2009 compensation expense is $20,780,000 over the 2004 test year level and represents the amounts identified as being charged to distribution O&M expense. The amount requested for rate years 2006 through 2009 is summarized below:

Rate Year	Amount Requested	Number of FTEs	% Increase
2006	$57,460,000	703.6	22.7%*
2007	$61,674,000	718.3	7.3%
2008	$64,670,000	722.3	4.9%
2009	$67,597,000	725.0	4.5%

*Over test year level

The Company provided the following details in support of its distribution compensation expense increase:

Overall, UI is proposing an O&M distribution FTE increase of 108.9 FTEs. The 108.9 FTEs is calculated by subtracting the test year level of FTEs from the level requested in 2009 (725-616.1).

The Company provided a listing of the new positions forecasted for retirements, normal attrition, developing and implementing solutions to address the aging distribution infrastructure and meet new compliance issues. The Company included a 3.1% vacancy factor into its compensation expense calculation. Therefore, the net FTE's the Company is requesting is approximately 106 and is detailed below.

In 2004, the Company's distribution FTE level was 616.1. In March of 2005, UI's finance reorganization increased the FTE level by 18 to 634.1. Response to Interrogatory EL-98. The Company indicated that there was no change in the nature of finance and related services provided to UI, only a change in the expense classes between direct and allocated charges. Response to Interrogatory EL-167.

UI testified a majority of the additional FTEs are needed in the Company's Electric System, Client Fulfillment and Information Technology business areas. Specifically, the Company needs 28 net FTE additions over the four-year period to address an aging workforce and aging infrastructure challenge. Testimony indicates that approximately 40% of the Electric System workforce will be eligible for retirement by 2009. The Electric System business area expects approximately 33% of the eligible employees to retire. As a result of the upcoming unprecedented infrastructure challenges, the lengthy training for many skilled positions, and the need to provide high quality service, it is the Company's belief that it is imperative to maintain a stable level of workforce capability. UI plans to hire replacement workers in advance of the expected retirements to allow the new hires the necessary time to develop skills and become fully functional. Failure to address this issue proactively will result in a significant reduction in the capability of UI's workforce. UI Brief, p. 43; Revised Attachment EL-162-3.

***56** Additionally, the Company argues that its Client Fulfillment area has been faced with staffing challenges related to employee transfers, retirements and other terminations. The Company has proposed an additional 40.8 FTEs for its Client Fulfillment business area. Revised Attachment 162-3.

Moreover, additional employees are needed for the Information Technology area. The Company has proposed 19 additional FTE's in order to provide needed support to other areas of the Company and meet compliance requirements. The company has identified compliance requirements to include the security of customer data, FERC/NERC standards and requirements, ISO-NE mandates, Homeland Security Act, USA Patriot Act, Customer Privacy Act, identify theft measures and the Sarbanes-Oxley Act. UI Brief, p. 45; Revised Attachment 162-3.

As evidenced below, the remaining hires are a combination of increases and decreases in other business areas.

Business Area	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**Total**
Client Fulfillment	13	18.5	5.3	4	0	0	40.8
Client Services	-1	0	0	0	0	0	-1.0
Corporate Affairs	-3	0	1	0	0	0	-2.0
Electric System	-3	3	8	11	4	5	28.0
Finance	-1	-1	0	0	0	0	-2.0
Human Resources	1	0	.5	0	0	0	1.5
Information Technology	2	8	5	2	2	0	19.0
Program Management Center	-1	1	2	0	0	0	2.0
UI Executive	2	0	0	0	0	0	2.0
Total	9	29.5	21.8	17	6	5	88.3
Finance Reorganization	18.0						18.0
Total New FTEs							106.3

Source: Revised Attachment EL-162-3.

UI developed its retirement projections based on historical trends for 2000 through 2004, the Company estimates that approximately 8% of the eligible employees (at least 55 with 10 years of service) will retire each year. For those employees who have reached age 58 with 30 years of service, the Company estimates that approximately 20% will retire each year. The Company testified that annual retirements are projected to range from 13.2% to 14.9% of eligible employees over the period 2005-2009. The Company indicated that historically 12% have retired. Response to Interrogatory EL-169.

***57** The AG believes that UI's Compensation Expense is inflated because the Company is using projected retirement rates that exceed historical levels. Second, the AG states that a reasonable increase in compensation expense is appropriate to ensure the continued provision of reliable service and improve its customer service however, the AG states that UI has provided adequate reliable service over the last four years. Moreover, the AG believes that the Company's proposal to increase staffing levels to replace its aging linemen and to bolster customer service is appropriate however, the AG believes that UI is seeking to hire employees in other areas where new positions are not necessary in these times of rising energy costs. Finally, the AG argues that the Department should reject the request to increase its wages by 4 to 4.5% per year, including a 6.7% increase of executive-level employees and deny escalating overtime. AG Brief, pp. 18-20.

The OCC acknowledged that some justification for additional employees exists due to workload, specifically, employees to meet compliance requirements, including Sarbanes-Oxley and replacements for some positions of technical workers. The OCC adds that retirements are normal and have occurred for years. Ratepayers should not be required to pay for two people to do one person's job on the presumption that someday the current employee will retire. The OCC recommends that based on the historical trend and the perceived need for some additional positions, the Company should be allowed the 18 workforce adequacy positions, one-half (15) of the client fulfillment positions, plus the SOX compliance position. In total, the OCC recommends that UI be allowed no more than 34 additional positions.

An additional concern the OCC has with the compensation expense is the purported wage increases that range from 3.8% to 6.7% for executives. The OCC believes that the Company's filing and responses failed to support or justify the escalation. The OCC notes that the actual calculation of the payroll escalation was not provided. Moreover, the OCC believes the increase is high specifically, referring to a September 2004 Hewitt news release indicated the salary increase projections for 2005 were ‘3.6 percent for salaried exempt employees, 3.5 percent for salaried nonexempt employees, 3.5 percent for non union hourly workers and 3.8 percent for executives.‘

The OCC believes that an addition of 34 employees is appropriate and recommends the Company be allowed 24 in 2005, five in 2006, three in 2007 and two in 2008. No justification exists for any additional new positions in 2009. The OCC recommends and provided detailed calculations that support the requested compensation expense reduction of $3,550,000 for 2006, $5,238,000 for 2007, $5,700,000 for 2008 and $6,120,000 for 2009.

UI is seeking total compensation expense of $57,460,000-$67,597,000 for rate years 2006-2009, respectively. These amounts include incentive compensation expense ranging from $5,649,000-$6,418,000. The Department addresses incentive compensation separately and has removed incentive compensation for this analysis. Therefore, the Company's net compensation expense proposal ranges from $51,811,000 in 2006 to $61,179,000 in 2009. This level of expense is for 703.6 FTEs in 2006 and increasing to 725 in 2009. The major reason for the increase is the adequacy of UI's workforce which includes Company's retirements, attrition and compliance activities. Overall, the increase from the test year to rate year 2009 is an increase in compensation expense of $19,791,000 and an increase in FTE level of 108.9.

***58** Based on the 2005 year to date retirements and historical trends, the Department finds that the Company's retirement projections are reasonable. UI projected 27 FTE retirements for 2005. As of August 15, 2005, the Company has had 20 retirements this year. The Company argued that this 2005 actual experience and the fact that more retirements tend to occur at the end of the year than at other months, the Company anticipates that its projection will be met or exceeded by the end of the year. Response to Interrogatories EL-351-1 and EL-352.

Moreover, the Department finds that UI's projected FTE levels for 2006-2009 are reasonable. UI's FTE level as of September 30, 2005, totaled 673. This level grossed up by the Company's 3.1% vacancy rate equals 694 FTEs. This figure exceeds the Company's 2005 projection of 684. [6] The Department finds that this level of employees will certainly allow the Company to prepare to replace its aging linemen, strengthen its client fulfillment customer service department and fulfill its public service obligations.

Although the Department believes that UI's low turnover and resultant highly skilled and experienced workers leads UI's compensation expense to be higher than average, the Department finds that UI's average salary per FTE is overstated.

Specifically, UI's average salary per FTE for rate years 2006 through 2009 range from $73,637 to $84,385, respectively. This figure was calculated by using the Company's 2006-2009 distribution compensation expense (less incentive compensation) divided by the number of proposed FTEs. [7]

In UI's last rate case, Docket No. 01-10-10, the total amount of payroll expense allowed was $50,210,073 for 800 FTEs. This equates to a 2002 average salary per FTE of $62,763. Assuming a 4% increase per year from 2003 to 2006, the average salary for 2006 would be $73,424. Based on this analysis, the $73,637 used by UI is acceptable. However, the $73,637 does not take into consideration the fact that UI's retiring employees will be replaced by lower paid employees. As indicated in Attachment EL-162-2, the Company has acknowledged that the average new hires will replace current employees at lower pay. Specifically, the Company provided the projected 2006-2009 average salary for current employees and requested new positions which can be used to estimate the salary of an FTE terminating or retiring. For current 2006 union and non union employees the average salary is $56,800 and $86,400, respectively. The 2006 new positions for union and non union positions are $45,600 and $84,900, respectively. The average union salary of $56,800 and non union salary of $86,400 for 2006 total $71,600. The $71,600 includes incentives and is $2,037 less than the Company's proposed $73,637 which excludes incentive compensation. Therefore, the Department believes that the $73,637 is overstated. Attachment EL-162-2.

***59** Additional testimony in Docket No. 01-10-10 indicated that 33% of UI's staff should have retired in the years 2003-2005 and the record in the instant docket indicates that another 33% should retire through 2009. 01-10-10 Decision, p. 57 and Vallillo PFT, p. 6. The above testimony indicates that between the years of 2003 and 2009, approximately 66% of UI's highly skilled and experienced workers will retire. Moreover, testimony indicates that the Company's historical retirement rate is 12% per year. If this is the case from 2003-2009, 84% of UI's staff essentially could retire. With these significant levels of retirement, the Company's average salary per FTE should decline over the years as oppose to increase steadily at more than 4% per year. This analysis is based on the fact that lower paid employees will be added to replace UI's highly skilled and experienced workers. [8]

In reviewing UI's actual distribution compensation expense (less incentive compensation) as of August 31, 2005, UI has incurred $29,644,000 ($33,315,000-$3,671,000). This amount annualized equates to $44,466,000 based on 657 FTEs (UI's average 2005 FTE level for the first 8 months as indicated in Attachment OCC-90-1). Inflating the 2005 annualized figure by 4.41% (2006 annual increases weighted as indicated in Attachment EL-163-1) equals $46,426,950. This amount divided by 657 equals a 2006 average salary per FTE of $70,665. This calculation indicates that UI's proposed amount is overstated.

Additionally, the record indicates that UI historically has over projected its FTE levels. Specifically, the Company over budgeted/projected its FTE levels by 28, 22, 24, and 31 for the years 2001-2004, respectively. Response to Interrogatories EL-90-2 and OCC-87; Late Filed Exhibit No. 89-1P. The Department estimates UI's 2005 UI's distribution compensation expense (less incentive compensation) to be $47,056,575. This estimate is higher than the estimate above to account for 27 (684-657) additional employees for the remaining 4 months of 2005. This is $1,722,425 less than the Company's 2005 projection of $48,779,000.

UI's average salary per FTE is similar to other regulated utilities in Connecticut. As evidenced in Docket No. 05-03-17, *Application of the Southern Connecticut Gas Company for a Rate Increase*, Southern proposed an average salary per FTE of $73,025 for the 2005-2006 rate years. [9] Moreover, in Docket No. 04-02-14, *Application of Aquarion Water Company of Connecticut to Amend Rates — Recalculation of Revenue Adjustments for Weather Normalization and Customer Growth in the Litchfield Division*, Aquarion 2003 average salary per employee totaled $61,468. [10] This amount escalated at 4% per year increases the average salary per employee to $69,143 in 2006. As evidenced above, UI, Southern and Aquarion's average salaries, excluding incentive compensation are similar. However, UI testified that its incentive compensation plans are an integral part of its market based compensation package. This being the case, it is important to note that UI's incentive compensation figures are significantly greater than Southern and Aquarion.

***60** The Department finds UI's average salary per FTE overstated and believes that $70,665 per FTE is reasonable. Therefore, the Department is disallowing $2,972 per FTE per rate year. This equates to a reduction to compensation expense of $2,091,099 for 2006, $2,134,788 for 2007, $2,146,676 for 2008 and $2,154,700 for 2009.

Finally, the Department believes that disallowing a portion of compensation expense based on average salary is fair and reasonable. This type of adjustment will allow the Company its proposed FTE level, wage increases and FTE related expenses (*i.e.* pension expense, employee benefits, management and professional training expense).

In summary, the Company's proposed compensation expense for the years 2006 through 2009 have been adjusted as follows:

15. Fringe Benefits

a. Medical Expense

The Company proposed medical expenses of: $5.758 million in 2006; $6.680 million in 2007; $7.626 million in 2008; and $8.531 million in 2009. This compares to test year actual 2004 medical expense of $3.198 million. The per-employee average benefit costs increases from the 2004 actual expense of $6,049 per employee to $13,883 per employee in 2009, a 230% increase in per-employee cost over the five-year period. [11] UI indicated a cost per employee of $8,367 for 2005, a 38% increase over year 2004 actual expense. The Company then escalated its 2005 per-employee cost by 15%, 14%, 13% and 12% for the rate years 2006, 2007, 2008 and 2009, respectively. Schedule WP C-3.28a A-D; Nicholas PFT, p. 30.

The OCC states that the minimal level of information provided by UI does not justify the increase in cost. The Company's calculation in the filing starts with a total Company headcount which includes UIL employees, with no indication or explanation whether or how the affiliate employees would be excluded from the cost calculation. Further, the responses to Interrogatories OCC-99 and EL-73 did not provide any documentation, studies, quotes or calculations despite the questions seeking such information, but simply referred to summary information provided by Hilb, Rogal and Hobbs Consulting Group and a paragraph indicating the Company's unsupported expectations. The OCC recommends that a 15.75% medical inflation rate be used for 2005, and an annual inflation rate of 12% thereafter. Therefore, the OCC recommends that the proposed medical expense be reduced by $370,000, $622,000, $820,000 and $909,000 in 2006, 2007, 2008 and 2009, respectively. OCC Brief, pp. 83-85.

The Company referred to four surveys/ studies in the Hilb, Rogal and Hobbs Consulting Group's summary information in attempting to validate its projected increases in medical expenses: The Hewitt — 2004 Healthcare Care Expectations Study that indicates that cost increases are expected to continue to rise at an overall annual rate of 14%. The Hewitt Study indicates that ‘most employers believe active employer and consumer involvement, not national health care, is the key to controlling healthcare costs‘; The Watson Wyatt Survey 2004 that indicates ‘increases in health care benefit costs, though easing somewhat, continue to grow at a double-digit rate‘; [12] The Deloitte — Top Five Benefit Priorities for 2004 that states ‘with health care costs projected to increase by double digits for the foreseeable future, we appear to be on the cusp of a seismic shift on the benefits landscape‘; and the 2004 Segal Health Plan Cost Trend Survey that indicates ‘while double-digit average increases in trend are expected to continue in 2004, the findings of this survey may signal a beginning of a downturn on the rate of increase from the prior three-to five-year period (13.1% to 15.7% range). Nevertheless, it is worth noting that cost trend rates are still three to five time[s] sic the rate of general CPI.‘ Response to Interrogatory EL-73.

***61** The Department notes that the Company has attempted to mitigate medical and dental costs by changing to lower cost programs and asking employees to share more of the costs of these benefits. Both management and union employees are required to pay an increased employee cost share (1.5% for management employees in 2005 and 3.5% for union employees from 2005 to 2011), and a new union contract calls for bargaining unit employees to utilize a less expensive core medical plan effective January 1, 2006. Nicholas PFT, pp. 29 and 30.

The Department is aware that there are innovative alternatives available to employers subsidizing health care that many companies are considering/utilizing to mitigate costs above and beyond increasing contributions or changing providers. The Department notes that these types of innovative measures are available to UI. Although the Department does not condone the Company's past efforts, it believes much more can be done to mitigate employee health care costs going forward. Accordingly, the Department rejects both the Company's and the OCC's recommended percentage increases for medical expenses.

The Company's own information indicates that medical expense increased 17.3% between the 2004 *pro forma* per employee cost to 2005. Schedule WP C-3.28a A. This increase is well beyond any mentioned in the surveys/studies that UI relied upon in this proceeding. Response to Interrogatory EL-73. Therefore, it is clear to the Department that UI's medical expenses are atypically high, and that management must do more to contain these costs.

The Department anticipates that UI's management will continue its efforts to contain medical expenses to a more reasonable level than that proposed. Accordingly, the Department reduces UI's medical expense escalation percentages to 12%, 11%, 10% and 10% for 2006, 2007, 2008 and 2009, respectively. This acknowledges the Company's surveys/studies citations aforementioned indicating that health care costs continue to grow at double-digit rates, and the 2004 Segal Health Plan Cost Trend Survey that indicates its survey may signal a downturn on the rate of increase from the prior three-to five-year period.

Using the Company's benefit headcount and adjustments indicated on Schedule WP C-3.28a A-D, and deducting the amount (by percentage) allocated to capital and non-distribution O&M, the Department calculates allowable medical expenses of: $5.396 million for 2006: $6.335 million in 2007; $7.032 million in 2008; and $7.731 million in 2009. The medical expense disallowed amounts are $362,000, $345,000, $594,000 and $800,000 in 2006, 2007, 2008 and 2009, respectively.

b. Payroll Taxes

As a result of its examination of employee compensation, the Department disallowed: $2,091,099 in 2006; $2,134,788 in 2007; $2,146,676 in 2008; and $2,154,700 in 2009 from UI's proposed compensation expense. Accordingly, the Department reduces the employer's portion of payroll taxes (FICA and Medicare combined) by a total of 7.65% of the disallowed compensation each year. The aforementioned compensation expense adjustments result in disallowed payroll taxes of: $159,969 in 2006; $163,311 in 2007; $164,221 in 2008; and $164,835 in 2009.

***62** The Department also disallowed UIL allocated incentive compensation of: $402,544 in 2006; $315,792 in 2007; $457,060 in 2008; and $495,904 in 2009. These disallowances result in decreases in payroll taxes of: $30,795 in 2006; $24,158 in 2007; $34,965 in 2008; and $37,937 in 2009.

The combined payroll tax disallowances above are: $190,764 in 2006; $187,469 in 2007; $199,186 in 2008; and $202,772 in 2009.

16. Pension/Other Post Retirement Employee Benefit

a. Background

UI has a qualified pension plan that covers the majority of its existing employees. Contributions to qualified pension plans are tax-deductible, and such plans are regulated by the Pension Benefit Guarantee Corporation (PBGC). The PBGC is a federal corporation created by the Employee Retirement Income Security Act of 1974 (ERISA) to encourage the continuation and maintenance of defined benefit pension plans, and to provide timely and uninterrupted payment of pension benefits to participants and beneficiaries in plans covered by the PBGC. The Company also has a non-qualified supplemental plan for certain executives, and a non-qualified retiree only plan for certain early retirement benefits. Contributions to non-qualified pension plans are not tax-deductible and such plan is not regulated by the PBGC.

For 2005, UI has made structural changes in the pension and other post retirement employee benefit (OPEB) plans. Effective April 1, 2005, for those hired into the bargaining unit and on May 1, 2005, for all other new employees, UI has implemented a new retirement plan that replaces the existing qualified pension plan and retiree medical plan benefits for new employees. Nicholas PFT, p. 25. The retirement plan for new employees will be a defined contribution plan, consisting of the current provisions of the 401(k) stock ownership plan (KSOP) for both pension and post-retirement medical benefits. New employees will not be part of the post-retirement medical plan, essentially reducing OPEB costs with the passage of time as new employees are hired. Nicholas PFT, p. 26. This new plan does not affect employees hired prior to the effective dates noted above. However, over the Rate Plan period, as new employees replace current employees who retire, the number of existing defined benefit pension plan participants will decrease each year. As a result, assuming no other changes in assumptions and that investment performance is as anticipated, pension and OPEB cost should decrease over time. Nicholas PFT, p. 25.

In the Application, UI requested total company pension expense of $11.7 million, $7.4 million, $6.9 million and $5.7 million, and OPEB expense of $5.4 million, $4.5 million, $4.3 million and $4.1 million, for the years 2006-2009, respectively. Nicholas PFT, p. 27. The Company calculated such expenses as of June 30, 2005. Response to Interrogatory EL-190, p. 2. UI subsequently revised its numbers based on more current assumptions as of October 27, 2005, and thus the Company's revised pension and OPEB expenses requested in rates are as follows: updated total pension expense of $14.4 million, $10.4 million, $10.3 million and $8.6 million, and revised total OPEB costs of $5.1 million, $4.6 million, $4.45 million and $4.24 million, for the Rate Plan years 2006-2009, respectively. Late Filed Exhibit No. 68.

***63** SFAS No. 87 expense, or pension expense, is based on the following elements which in total equal net periodic benefit cost.

Service cost + Interest cost-Expected return on assets + Amortization of Unrecognized (Gain)/Loss Prior service cost Transition Obligation (Asset) ______________________________ Net Periodic Pension Cost

Generally, service cost is the increase in projected benefit obligation due to the accrual of benefits that occurred in the current period. Interest cost reflects the growth in present value of projected accrued benefit obligations as they come one period closer to payment. These costs are offset by the expected return on assets, which equals the fair market value of plan assets times the expected long-term rate of return on plan assets. To the extent these components deviate from actual or result from plan changes, the difference accumulates in asset or liability accounts and is amortized over a number of years into (gains)/losses, prior service cost, and transition obligation (asset). To the extent that actual and expected returns on plan assets are different, this is accumulated in unrecognized net (gains) or losses. Affecting each element of net periodic benefit cost are actuarial assumptions such as the discount rate, expected return on assets, and average wage increase.

The underlying detail to these updated annual expense estimates is shown as follows:

Response to Late Filed Exhibit No. 68-1, 68-2 and 68-3.

SFAS No. 106, or OPEB expense, establishes accounting standards for postretirement benefits other than pensions. This statement focuses principally on health care benefits, where the employer promises to provide health benefits after an employee retires. Such benefits are other post retirement employee benefits and the expense is calculated with one additional assumption, the health care cost trend rate. This represents the expected annual rates of change in the cost of health care benefits currently provided by the post retirement benefit plan.

UI capitalizes a portion of its pensions, OPEB and 401(k) expenses into ratebase. The amounts the Company is requesting in rates are adjusted for amounts allocated to capital and non-distribution O&M. Response to Interrogatory EL-197. The amounts allocated to non-distribution by year includes that portion allocated to non-distribution capital plus non-distribution O&M, such as, transmission, CL&M and GSC. Late Filed Exhibit No. 69.

b. Actuarial Assumptions

The key actuarial assumptions used in determining the Company's pension expense are: 1) discount rate, 2) expected return on assets, and 3) average wage increase. Discount rate is used to evaluate the present value of the plan liabilities. The higher the discount rate the lower the present value of the liabilities resulting in lower pension expense. Expected return is an assumption, not an actual return, and is a product of plan investment mix and the expected earnings on such mix. The higher the assumption the more the plan assumes it can earn resulting in lower pension expense. The average wage increase is the assumed increase in annual wages for all employees in the plan. The higher this assumption, the higher the pension expense.

***64** The Company states that its discount rate is based on the current Moody's Corporate Aa bond rate and this is based on corporate bonds with maturities of 20 years and above. Response to Interrogatory EL-196. The Company's original filing used a 5.75% discount rate in calculating expense for all years except 2006 where 5.0% was used. The Company notes that was the approximate Moody's Aa rate as of June 24, 2005. Nicholas PFT, p. 28. The Company's final expense for 2006 was recalculated as of October 27, 2005, using a discount rate of 5.5% which was Moody's Aa rate at that date. Late Filed Exhibit No. 68, p. 2. Since this rate serves to discount the pension liabilities to the present, a higher discount rate would result in lower liabilities and thus less current pension expense.

The Company used an 8.0% expected return on assets assumption for all years of the Rate Plan period. Response to Interrogatory EL-193, p. 2. UI noted that this rate is based on estimates provided by its pension plan asset manager, the Russell Company. Response to Interrogatory EL-188. In developing its return forecast, the Company assumed a 65%/35% equity/fixed split in its investment mix compared to a 70% equity investment position for previous years. Nicholas PFT, p. 27. Since this rate assumes the amount one can earn on plan assets, a higher expected return would lower pension expense.

In the Company's filing it has used an average wage increase assumption of 4.5% for all years of the Rate Plan period. Nicholas PFT, p. 27. UI indicates that this is the anticipated rate it expects to pay in future periods. Tr. 10/ 17/05, p. 1465. A higher average wage increase would result in greater benefits earned by plan participants and thus would increase pension expense.

The same discount rate and expected return on plan assets are used to calculate OPEB expense. In addition, the Company also uses a healthcare trend rate assumption for pre-65 and post-65 retirees of 11% and 6% for 2006 and grading down 1% each year to 10% and 5.5% for 2007, 9% and 5.0% for 2008, and 8% and 5% for 2009, respectively. Late Filed Exhibit No. 68. The healthcare trend rate assumptions used in the plan period reflect UI's expected cost increases for next year based upon information from the carriers. Response to Interrogatory EL-193. A higher healthcare cost trend rate would mean higher benefit costs and thus increased OPEB expense.

c. Department Analysis

1. Discount Rate

The Company originally calculated its 2006 expense using a 5.0% discount rate assumption. UI recalculated the 2006 expenses using a 5.5% assumption determined at October 27, 2005. As of October 27, 2005, the Treasury 20-year Constant Maturity Treasury Index (CMT) was 4.84%, a 56 basis points increase from 4.28% at June 24, 2005. This increase was consistent with the 54 basis point rise in the Moodys Aa rate (4.96% on June 24, 2005), and the Company's use of 5.5% rate in its recalculation of expenses as of October 27, 2005. The Department evaluated the Treasury 20-year CMT rate as of the last day of hearings, November 9, 2005, and found that this rate was 4.93% versus 4.28% at June 24, 2005, a 65 basis points increase. Given the Treasury 20-year CMT's similarity in movement to the Moodys Aa rate, and the data provided by UI showing companies surveyed using 5.80% as a median discount rate (in the 50th percentile), the Department finds that 5.75% is a reasonable discount rate for 2006. The Department also finds this consistent with the 5.75% discount rate that UI is using in all other years of the Rate Plan. Thus, the Department requires a discount rate of 5.75% to be used calculating UI's 2006 expenses in rates. The Department finds UI's discount rate assumption of 5.75% appropriate for 2007-2009. Therefore, versus UI's final numbers, based on the Company's sensitivity analysis, the Department requires an additional $920,000 ($368,000 X 2.5) reduction in pension expense for 2006. The adjustment for OPEB expense is $190,000 ($76,000 X 2.5) reduction for 2006. Response to Interrogatory EL-195.

***65** The Company, in its written exceptions, argued against increasing the discount rate from 5.5% to 5.75% for 2006. UI states that it is required to utilize the Moody's Corporate Aa rate as of December 30, 2005. UI Written Exceptions, p. 29. The Department realizes UI's concern; however, the Department cannot introduce new market information after the record has been closed in this proceeding. The Department also notes that improved market performance as of December 30, 2005, would also increase UI's expected asset values over the entire rate plan period thereby decreasing pension expense. This end of the year increase in asset valuation would considerably offset any increase in pension expense due to a decrease in the discount rate for 2006. The Department finds 5.75% to be a reasonable discount rate for 2006 and is consistent with the discount rate UI is using in all other years of the rate plan.

2. Expected Return on Assets

The Company supports the use of an 8% expected return which is based on the Russell Company's most recent Capital Market Research Group Forecast as of June 30, 2004. Response to Interrogatory EL-215-1. The survey data that the Company provided, which included S&P 500 companies 10K reports for fiscal year 2004, showed that the median expected return assumption used by those companies (in the 50th percentile) was 8.5%. Response to Interrogatory EL-194. Further, the August 2005 Mercer Study indicated that for companies that disclosed their intended return rate for 2005, the expected returns remained virtually the same as those for 2004. Late Filed Exhibit No. 65, p. 24. Since the median assumption of companies surveyed is 8.5%, and this is likely the case for 2005, the Department finds that UI's 8.0% assumption is somewhat conservative. Thus, the Department finds that an expected return assumption for UI of 8.25% is more reasonable; it moves the Company closer to the median, and thus, is required in UI's calculation of pension/OPEB expense charged customers in rates. Based on the Company's sensitivity analysis, this reduces allowed pension expense each year through the Rate Plan period by $697,500 ($279,000 X 2.5), and for OPEB $47,500 ($19,000 X 2.5). Response to Interrogatory EL-195.

3. Average Wage Increase

The average wage increase used by UI in determining its pension expense is 4.5%. Per the Company's data, its projected wage increase for Union employees, about half of its work force, is 4.25% annually (2006-2008) and 4.0% in 2009. All other employees average 4.5% each year. Response to Interrogatory Attachment EL-163-1. The data which UI provided shows that the median wage increase assumption used for all companies surveyed was 4.0%. Response to Interrogatory EL-194. Accordingly, the Department finds that a 4.25% assumption is reasonable and more closely aligns UI with the median. To be consistent with the payroll section of this Decision, the Department uses the allowed weighted average salary increase of 4.41% for years 2006 through 2008 and 4.32% for 2009. Response to Interrogatory EL-163-1. Therefore, the Department requires an average wage increase of 4.4% for years 2006 through 2008 and 4.32% for 2009 to be used in calculating UI's expenses in rates. Based on the Company's sensitivity analysis, pension expense is reduced by $281,000 ($281,000 X 1.0) for 2006 through 2008 and reduced by $505,800 ($281,000 X 1.8) for 2009. Id; Response to Interrogatory EL-195.

4. Asset Performance

***66** UI indicated that its original calculations were based on an expected asset level of $294.7 million at year end 2005. Response to Interrogatory EL-190-4, p. 4. However, in its Late Filed exhibits based on the status at October 27, 2005, UI determined that it would now be assuming, absent a recent contribution made, a pension asset level of approximately $281.4 million at year end 2005 due to its investment performance. Late Filed Exhibit No. 68. The Company noted that this translates into an additional unrecognized loss of $13.3 million ($294.7M-$281.4M) over the original expenses. Since UI is allowed to amortize such losses into expense over a 10 year period, UI notes this resulted in an increase of $1.33 million to expense in

2006 and forward. Tr. 11/9/05, pp. 2335 and 2336. Further, the Company indicated that it had contributed another $5.5 million to assets to avoid a minimum pension liability bringing assets to $286.9 million. As such, assuming now $7.8 ($294.7M - $286.9M) million of less assets, earnings would be $.624 million ($7.8 million X 8%) lower each year over the plan period. Accordingly, the total effect of asset investment performance as of October 27, 2005 was an increase of approximately $1.95 million to pension expense over the Company's originally filed numbers. UI made this adjustment in its Late Filed exhibits.

The Department notes, however, that as of the last day of hearings, November 9, 2005, the investment horizon had improved since October 27, 2005. Using the S&P 500 as a reasonable proxy for equity performance, the index had risen to 1,220.65 on November 9, 2005 from 1,178.90 at October 27, 2005. This represents about a 3.5% increase in investment performance. The effect on $281.4 million of pension assets would be approximately as follows: The equity portion of assets is about $182.9 ($281.4 X 65%) million. Assuming another 3.5% return since October 27, 2005, yields an additional $6.4 million ($182.9M X 3.5%) gain bringing assets to an assumed $287.8M ($281.4M + $6.4M) at year end 2005. The additional unrecognized loss is now $6.9 million ($294.7M - $287.8M) which the Company is allowed to amortize over a 10-year period, or an increase to originally filed pension expense of $690,000, versus $1.33 million recalculated by UI. Secondly, given the November 9 status and UI's recent $5.5M contribution, assets at the end of the year are adjusted to $293.3 million ($286.9M + $6.4M). This represents a shortfall of only $1.4 million over the $294.7 million the Company had originally used in its calculations. As such earnings would be $112,000 ($1.4M X 8.0%) less each year into the plan period compared to the Company's originally filed numbers. The total adjustment is $802,000 ($690,000 + $112,000). Thus, the Department reduces the Company' final calculated pension expense (October 27, 2005 status) for each year of the Rate Plan period by $1.15 million ($1.95M-$.802M).

The impact on all the above to OPEB expense would be as follows: As of October 27, 2005, the expected OPEB asset level was approximately $24.9 million for year end 2005 compared to UI's original calculation of $25.9 million. UI states that this contributes to an increase in OPEB expense for each year in the Rate Plan by approximately $175,000. Late Filed Exhibit No. 68. As of November 9, 2005, it yields an additional $611,275 ($24.9M X 70% X 3.5%) gain increasing the OPEB asset value to an assumed $25.561 million ($24.9M + $611,275) at year end 2005. Response to Interrogatory EL-204. The additional unrecognized loss is now $341,725 ($25.903M-$25.561M) resulting in an increase to OPEB expense of $34,173 each year. As such, earnings would be $27,338 ($341,725 X 8.0%) less each year into the plan period compared to UI's originally filed numbers. By interpolating for asset values for OPEB as of November 9, 2005, the Department calculates the total adjustment or increase in OPEB expense of $61,511 ($34,173 + $27,338) versus the $175,000 increase calculated by UI as of October 27, 2005.

5. Healthcare Trend Rate

***67** In calculating its OPEB expenses, the Company also brings in a healthcare trend rate for pre-and post-65 retirees based upon information from the carriers. UI used a pre-65 healthcare trend rate assumption of 11% in 2006 trending downward to 8% in 2009. Late Filed Exhibit No. 64. Based on survey data provided from Watson Wyatt, dated 8/1/04, it shows healthcare trend rates on a composite basis for pre-and post-65 retirees with a median of 10% for 2004. Response to Interrogatory EL-193. The survey data is based on a composite rate, meaning it is weighted for pre-and post-65 year old retirees. Pre-65 retirees are more expensive than post-retirees, since the latter are covered by Medicare. UI's actuaries do not calculate a composite rate and report separately for pre-and post-65 year old retirees. Response to Interrogatory EL-194. Although UI does not calculate a composite rate, UI's actuaries have determined that approximately 75% of the plan's ABO is attributable to post-65 coverage. The Department has evaluated the cost trend rate for UI's OPEB expenses and finds that it is reasonable and the assumptions are within the reasonable range of outcomes.

6. 401(k) Employee Stock Ownership Plan (KSOP)

UI is seeking full recovery of its matching contributions made by the Company to the 401(k) Employee Stock Ownership Plan (KSOP) along with incremental contributions for new employees in lieu of their participation in the pension and OPEB plans. Revised Response to Interrogatory EL-218. UI projects the full amount of KSOP contributions to be $2.782 million in 2006, $3.117 million in 2007, $3.465 million in 2008, and $3.788 million in 2009. As discussed above, new non-union employees (hired after May 1, 2005) and union employees (hired after April 1, 2005), an enhanced KSOP contribution has replaced pension plan coverage for these employees. Since these specific contributions are not KSOP matching contributions, they would be excluded from the total KSOP contributions disallowed in the Department's calculation. The actual KSOP matching contributions would be $2.478 million in 2006, $2.641 million for 2007, $2.801 million in 2008, and $2.928 million in 2009. The amount requested in rates is the amount attributable to distribution O&M expense including the offset for the allocated to capital and non-distribution O&M portion. Revised Response to Interrogatory EL-217, p. 2.

The Department has reviewed the issue of matching contributions as they relate to the Company's KSOP Plan. In the 01-10-10 Decision, the Department found that matching provides a benefit to employees, but restricted the amount of matching recovery allowed. The Department holds, consistently, this manner of treatment in this rate case. In this regard, keeping the matching formula intact, the Department allows full recovery of matching contributions for all UI employees, excepting those who are entitled to benefit under the EICP and the MCP. The Department estimates conservatively that 50% of the employee matching expense is due to employees that do not receive any form of additional compensation beyond salary such as EICP and MCP. Accordingly, the Department allows $1.239 million for 2006 ($2.478M X 50%), $1.321 million for 2007 ($2.641M X 50%), $1.401 million for 2008 ($2.801M X 50%), and $1.464 million for 2009 ($2.925M X 50%) or full recovery for this group. For the remainder, where it is estimated employees that already have significant potential of receiving additional compensation benefits through rates, the Department finds that ratepayers should not be required to fully fund their matching contributions as well. Accordingly, for those employees entitled to benefits under the EICP and MCP, matching expense will be borne 50% by shareholders and 50% by ratepayers. The Department finds it reasonable to allow $0.620 million for 2006 ($1.239M X 50%), $0.660 million for 2007 ($1.321M X 50%), $0.700 million for 2008 ($1.401M X 50%), and $0.732 million for 2009 ($1.464M X 50%) to be borne by ratepayers. Therefore, including full recovery of the contributions in lieu of pension for new hires, the Department allows $2.163 million for 2006 ($1.239M + $0.620M + $0.304M), $2.457 million for 2007 ($1.321M + $0.660M + $0.476M), $2.765 million for 2008 ($1.401M + $0.700M + $0.664M), and $3.056 million for 2009 ($1.464M + $0.732M + $0.860M) in total for KSOP expense. As such, the total disallowance for KSOP matching contributions is $0.620 million for 2006, $0.660 million for 2007, $0.700 million for 2008 and $0.732 million for 2009. A summary of the KSOP expenses is presented in the following table.

7. Pension Regulatory Asset

***68** UI noted that there is a potential assumption change, not reflected in the Rate Plan, regarding the mortality table used to estimate the time period individuals will actually receive pension payments. Nicholas PFT, p. 29. The IRS-mandated set of tables for these calculations is currently the 1983 Group Annuity Mortality (GAM) tables. The IRS has not prescribed a change from this mortality table at this time. If the IRS should update the mortality table, UI's actuaries have estimated that it would increase expense in the qualified plan over the amounts presented in this filing by approximately $500,000 per year. UI also believes it is possible that expense could increase by even more if the IRS mandates the use of a different mortality table. UI has requested that the Department set up a regulatory asset for this possible increase in expense for recovery in the next rate case. However, the Company has testified that it is possible that there may be no changes at all during the Rate Plan period. Tr. 10/24/05, pp. 2029 and 2030. Due to the great uncertainty as to when or if the IRS should mandate a change to the mortality tables, the Department finds that it is premature to establish a regulatory asset at this time. The Department will review recovery, if necessary, in the next rate case proceeding.

8. Pension/OPEB Summary

A summary of all the adjustments and allowances for pension and OPEB expenses is provided in the following table:

17. Rate Case Expense

UI projected $1,548,000 for rate case expenses to be amortized at $387,000 per year from 2006-2009. Schedule WP C-3.35 A-D. In Late Filed Exhibit No. 42, UI revised the projected expenses to $1,471,540. UI believes the projected rate case expense of $1,471,540 is appropriate and should be approved by the Department. UI Brief, p. 58.

The Department reviewed documentation of the expenses as provided in response to Interrogatories EL-243, EL-359, EL-360 and Late Filed Exhibit No. 42. In addition, the Company testified as to the nature and need for each line item of rate case expense. Tr. 10/14/05, pp. 1066-1073. The Department concurs with UI that $1,471,540 is reasonable and approves the four-year amortization in the amount of $368,000.

18. System Integrity and Aging Infrastructure Management Expenses

'System integrity' is the term UI uses to describe the capacity, reliability and overall safety of its electric distribution system. UI states that it anticipates increasing challenges to its system integrity during the Rate Plan period and beyond. The Company states that system integrity risk due to aging infrastructure is a routine part of the business; however, it has an exceptionally large volume of assets that are now entering into the 4th quartile of their operational lives. According to UI, this will increase the probability of degrading reliability going forward. Reed PFT, pp. 2 and 3.

UI states that age and condition of equipment are important factors that influence the increase in the potential rate of failure. Furthermore, failure rates increase over the operational lifecycle of a piece of equipment, and escalate most significantly during the 4th quartile. *Id.*

***69** UI states that its system underwent substantial growth in customers and energy utilization from the mid-1960s to the mid-1970s, during which its customer base grew by approximately 20% and its average kWh sales by approximately 73%. Substantial infrastructure was added, replaced or upgraded during this time, creating a 'wave' in distribution infrastructure age demographic. Much of its infrastructure will therefore be 40-50 years old during the next decade. The Company further states that the sheer volume of these assets, coupled with uncertainty surrounding their mode and frequency of failure, contribute to the quantity and complexity of failures that can result in outages. The Company also states that the aging infrastructure situation is not unique to UI; rather, it is common to most electric, gas and water utilities in the Northeast. *Id.*, pp. 5 and 6.

The Company states that its system integrity challenge is compounded by four additional issues:

• The increased need for quality data to support analysis and decision making;

• The energized and integrated nature of the electric distribution system;

• The availability of appropriate engineering and lineworker expertise;

• The potential for technical obsolescence resulting from industry changes.

The amount in the Rate Plan included for the system integrity initiatives is as follows.

System Integrity Initiative Expenditures

($ in millions)

	2006	2007	2008	2009
Expense	$2.7	$4.7	$4.1	$3.4

***Id.*, pp. 7 and 14.**

UI's approach to managing its system integrity challenge places strong emphasis on analysis and planning. The Company plans on increasing and enhancing equipment inspections, expanding equipment analysis and advancing the scope of its infrastructure replacement programs. In the near term, UI will focus primarily on expanding its inspection and analysis capabilities to provide the decision-making framework to guide future infrastructure investment, which is then followed by a gradual increase in the amount of asset replacement spending. The inspection and analysis programs will provide:

• The impact each asset class can have on reliability performance;

• The scope and schedule of the replacement programs;

• Priorities of the different programs relative to their contribution to system integrity and other key value measures; and

• The refinement of planning assumptions with empirical information.

Reed PFT, pp. 14-17.

The Company's plans to implement the following measures during the term of the Rate Plan:

• Phase 1: Develop a system model/profile;

***70** • Phase 2: Identify types of risk, the indicators of the risk and populating the system model with risk attributes;

• Phase 3: Simulate the risks and the impact on performance;

• Phase 4: Develop mitigation strategies and objectives.

The schedule for implementing these measures during the Rate Plan period, as reflected in the Company's planned expenditures, is as follows:

• 2006: Phase 1 and Phase 2 on initial asset classes;

• 2007: Phase 1 on remaining asset classes, and Phase 2 and 3 on initial asset classes;

• 2008: Phase 2, 3 and 4 ongoing, with impact analysis on high priority asset classes;

• 2009: Phase 2, 3 and 4 ongoing, with data gathering/analysis on remaining asset classes, replacement programs evolving and expanding.

Response to Interrogatory EL-336.

No party or intervenor opposed UI's system integrity initiatives, although the AG urged the Department to ‘carefully scrutinize‘ the Company's proposals. AG Brief, p. 24.

The aging of utility infrastructure was discussed extensively in Docket No. 03-07-02. Further, industry literature is replete with discussions on aging industry infrastructure and technical personnel throughout the energy industry. The Company provided data regarding the age of its distribution plant in Late Filed Exhibit No. 22. The value of the Company's plant added in 1966-1975, escalated to 2004 dollars, is approximately $385 million. The value of the plant added in the following 10 years, 1976-1985, is $174 million, or less than half the value of the plant referred to by the Company as aging. Late Filed Exhibit No. 22, pp. 2-4. The Department accepts the concept that distribution company equipment is aging for the reasons discussed by the Company. The Company's proposals for mitigating the impact of aging plant appear well thought out and involve moderate expenditures, therefore the Department approves them.

The Department routinely follows and examines issues related to reliability and the material condition of Company's plant through two proceedings: the annual TDRP proceeding and the biennial Line Maintenance Plan proceeding. The Department will monitor the progress of the Company's programs to mitigate aging plant in those proceedings.

19. Construction Program Expense Impacts

In Section III.D.1, above, the Department reviewed UI's construction program and made adjustments to plant in service, as necessary. In addition, the Department concluded that certain capital projects will result in expense savings, which UI did not include in its Application. The Department includes expense savings in the calculation of revenue requirements for the Rate Plan for the distribution substation conversion and the air circuit breaker project.

The annual expense savings for the distribution substation conversion are $20,000. Late Filed Exhibit No. 19. Using the half-year convention for placing plant in service the Department calculates total savings of $10,000, $30,000, $50,000 and $70,000 for the years 2006-2009, respectively.

***71** The annual expense savings for the air circuit breaker program are $4,248. Late Filed Exhibit No. 17. Using the half-year convention for placing plant in service the Department calculates total savings of $2,125 for 2008 and $6,375 for 2009.

In addition, the Department removed the capital costs for the 2009 desktop refresh program. The Department believes that $100,000 ($100 per computer) is a reasonable estimate for maintaining the desktops one additional year, and therefore, increases 2009 expense by $100,000.

In summary, the Department decreases 2006 expenses by $10,000, 2007 expenses by $30,000 and 2008 expenses by $52,125. The Department also increases 2009 expenses by $23,625.

20. Depreciation Expense

a. Depreciation Study Recommendations and Adjustments

The Company last submitted a depreciation study to the Department in Docket No. 89-08-11, *Application of The United Illuminating Company for an Increase in Rates,* that was conducted in 1988 (1988 Study). The Company presented a new depreciation study in this case (Study), done by an external consultant, Management Applications Consulting, Inc. Schedule H-1.6. As in previous cases, the Company used the straight-line method, remaining life technique and vintage/broad group method, or average life group, for compiling depreciation of each type of plant.

UI's Application reflects depreciation expense of $25.408 million, $30.582 million, $32.870 million and $34.493 million for years 2006, 2007, 2008 and 2009, respectively. Schedule C-3.34 A-D. Depreciation expense is calculated by multiplying the annual average plant in service by the remaining life accrual rate. The accrual rate is determined by the Company's Study.

The Study uses various statistical analyses to determine the estimated remaining life for each class of assets in service as well as salvage values and costs of asset removal. The estimated remaining lives determined within the Study were then used to set each class of asset's remaining life accrual rate. The Study recommends increasing or decreasing the remaining lives for a number of asset classes. The total plant level average service life in the study was 34.1 years, compared to the average service life of 34.4 years in the 1988 Study. However, there are several accounts where the Study recommends substantial changes in service lives from those previously approved. In the majority of those cases, the adjustments are well-reasoned and within the bounds of standard depreciation practices and/or are revisions to a longer service life, reducing immediate revenue requirements.

The Department has reviewed the Study and concludes that the depreciation lives, methods and amounts recommended therein are acceptable, except for the exceptions noted below.

1. Account 364 — Poles

The Company proposes increasing the net salvage in this account from -15% to - 25%. The OCC recommends only allowing a net salvage of-20%, since the Company has ‘shown a willingness to be conservative‘ in implementing large changes in depreciation charges. OCC Brief, p. 69. UI states that the Study indicated an even higher net salvage of greater than -30%. However, since standard depreciation practice is to implement large indicated changes in stages, the Company reduced the net salvage to -25%. UI Reply Brief, p. 36; Tr. 10/11/05, p. 727.

***72** The Department agrees with the Company. Since the Study indicated a sudden substantial change in net negative salvage, it is appropriate to change the salvage by some amount less than the full indicated net salvage. Further, the industry average for net salvage in this account is -32.6%, lending some credence to a larger negative net salvage. Response to Interrogatory EL-63. Therefore, the Department allows -25% as an appropriate net salvage for this account.

2. Account 366 — Underground Conduit

The Company proposes increasing the average service life in this account from 65 years to 75 years. The OCC states that there is a ‘mass undertaking and replacement of plant in this account‘ and that over 50% of the plant is over 60 years old, and therefore the average service life should be much longer than 75 years. OCC Brief, p. 72. UI states that the recommended service life is the result of standard depreciation analysis of the plant in the account. Study, p. 13.

The Department accepts the Company's recommendation for an increase in the average service life of this account to 75 years. The OCC did not present a basis for an increase in life beyond that already indicated by the Study. The analysis already incorporates retirements of plant in this account, which, according to the analysis leads to an average service life of 75 years. Further, if the indicated life were longer, the Department adopts the standard depreciation practice of making only moderate changes in depreciation indications that are based on only one study. The Department therefore rejects the OCC's recommendation.

3. Account 369 — Services

The Company proposes increasing the net salvage in this account from -20% to - 40%. The OCC recommends only allowing a net salvage of -30%, since the increase is large and the industry average for this account is -29.5%. OCC Brief, p. 70. UI states that the Study indicated a much higher net negative salvage. However, since standard depreciation practice is to implement large indicated changes in stages, the Company limited the net salvage to -40%. UI Reply Brief, p. 36; Tr. 10/11/05, p. 727; Study, p. 14.

The Department accepts the OCC's recommendation for Account 369. It is standard depreciation practice to limit the magnitude of changes from between studies, and, in this case, the Department believes that an increase in net salvage from -20% to -40% based on one study is excessive. The Department therefore approves a net salvage of -30% for this account. This change decreases negative net salvage by $1.8 million over the remaining life, and reduces depreciation expense by approximately $70,000 each year. Late Filed Exhibit No. 21.

4. Account 370 — Meters

The Company proposes reducing the average service life in this account from 30 years to 25 years. UI states that the electronic meters have been shown to have a shorter life expectancy than the old-electro-mechanical meters. Study, p. 14. The OCC states that customers did not request their old mechanical meters to be replaced with electronic ones, and therefore should not bear the burden of the increased depreciation expense. OCC Brief, p. 71.

***73** The Department believes the reduction in average service life in this account is appropriate. The Company changed its customers to an electronic-based network meter reading system several years ago, which offers a number of benefits including cost savings, which are reflected in the Application. However, this type of metering is characterized by a somewhat shorter service life than the older mechanical meters, as is documented in industry literature. Response to Interrogatory EL-61. The changes in depreciation that result from this changeover are moderate and reasonable, and the Department, therefore, accepts them.

5. Account 372 — Water Heaters

The Company proposes decreasing the net salvage in this account from a +20% to zero. The OCC recommends maintaining net salvage at +20%, since the industry average net salvage is about +20%, and implementing this change unfairly burdens current customers with the long-term effects of negative net salvage. OCC Brief, p. 70. UI states that the Study indicated a net salvage of approximately -5% in this account, which is being driven lower by labor and disposal costs. Tr. 10/11/05, p. 731; Study, p. 15.

Similar to other accounts in which net salvage is being adjusted in large increments, the Department believes that some adjustment needs to be made to reflect experience, but a 20% adjustment based on one study is too large. However, since the analysis indicates that the changes occurring in net salvage are real, it is not appropriate to hold the net salvage at +20%, as the OCC suggests. The Department therefore approves a net salvage of +10% for this account. This change decreases depreciation reserve by $800,000 over the remaining life, and reduces depreciation expense by approximately $55,000 each year. Late Filed Exhibit No. 21.

6. Account 390 — Structures and Improvements

The Study includes a recommendation to decrease average service lives from the 50 years recommended in the prior study, to 35 years. The Study bases the decrease on actuarial analyses of the group history and judgment. The plant balance in Account 352 was $832,992 as of December 31, 2003. Study, p. 17.

It is general practice that depreciation accrual rates are reviewed at least every five years. However, in the instant proceed it has been 16 years since the last study. Therefore, it is understandable that review of accounts may reveal some instances where there maybe be a large change in average service lives. However, it is also general practice that service lives are not radically altered from one study to the next; but rather, should be gradually adjusted in smaller, more frequent increments. This concept is briefly discussed on p. 7 of the Study. [13] In the case of Account 390, the change in service life is a reduction of 30%, which is quite large.

***74** Additionally, the property in Account 390 is very similar to Account 352, Transmission Structures and Improvements, which has a 45 year life. The Department does not disagree that the actuarial analysis indicates a reduced life, however, it is not apparent at this time that the average service life in Account 390 should be reduced to less than Account 352. Therefore, the Department will reduce the average service life in Account 352 from 50 years to 45 years. The Department estimates that this equates to a reduction in depreciation expense of approximately $5,300 each year.

b. Frequency of Depreciation Studies

The Department notes that it has been approximately 16 years since the last depreciation study. In the study submitted in this proceeding, there have been a number of accounts (*e.g.* Account 370, Meters) where changes in average service life are being driven by changes in technology. However, one depreciation study every 16 years is not adequate to capture significant changes in average service lives. It is normal practice to conduct a new depreciation study approximately every 5 years. Since the current study identifies a number of accounts where the indicated average service life is changing substantially, a large time has elapsed since the last study and since recent changes in technology are driving changes in a number of accounts, the Department believes a new depreciation study needs to be conducted in several years. The purpose of the study would be to confirm changes that appear to be indicated by the current study. Accordingly, the Department will order the Company to conduct a new depreciation study in the first rate proceeding that occurs after January 1, 2010.

c. Impacts from Changes to Construction Program

As discussed above, the Department adjusted plant in service for changes made to UI's construction program. Consequently, the Department must also adjust depreciation expense. UI's depreciation study indicates that computers have a four-year depreciable life. Schedule H-1.6, p. 18. Therefore, the corresponding decrease to depreciation expense is $292,500 for 2009.

d. Summary

As discussed above, the Department decreases depreciation expense by $130,300 for each year of the Rate Plan to account for changes the Department makes to certain accounts in UI's depreciation study. In addition, the Department reduced depreciation expense by $292,500 in 2009 because of the elimination of the desktop refresh program. Therefore, the net decrease to depreciation expense is $130,300 annually from 2006 through 2008 and $422,800 in 2009.

21. Transmission A&G Allocation

UI first assigns all administrative and general (A&G) expenses to the distribution side of the business. UI then allocates a percentage of the total A&G to the transmission side of the business. For each year of the Rate Plan, UI used an allocation factor of 4.18%. Schedule C-3.29.

The Department adjusts UI's expenses by $12,841,000, $12,656,000, $13,520,000 and $14,653,000 for the years 2006-2009, respectively. Net of depreciation, amortization and the transmission A&G allocation, $12,340,000, $12,146,000, $13,048,000 and $13,925,000 for the years 2006-2009, respectively, is subject to the transmission A&G allocation percentage. Therefore, the Department increases expenses by $515,803, $507,709, $545,413 and $582,050 for the years 2006-2009, respectively, to account for the percentage of the total A&G expense decrease that should be allocated to the transmission side of the business.

22. Expense Summary

***75** In summary, the Department decreases the Company's total requested operating expenses, excluding changes for income taxes, for 2006 through 2009 by $12,841,000, $12,656,000, $13,520,000 and $14,653,000, respectively. These adjustments include the expense impacts discussed in the ESWC section. The resulting allowed total operating expenses for 2006 through 2009 are $191,513,000, $200,024,000, $207,694,000 and $212,587,000, respectively.

F. INCOME TAX EXPENSE

The Company proposed federal (current and deferred) and state income taxes of $13.060 million, $14.050 million, $16.669 million and $17.216 million in years 2006, 2007, 2008 and 2009, respectively. Schedule C-1.0 A as adjusted by Second Revised Attachment LF-1-1. As a result of the Department's adjustments in this Decision, the Department has calculated combined income taxes as $9.339 million, $10.382 million, $12.508 million and $12.981 million in 2006, 2007, 2008 and 2009, respectively. Therefore, the Department reduces Income Tax Expense by $3.715 million, $3.668 million, $4.164 million and $4.236 million in years 2006, 2007, 2008 and 2009, respectively.

G. GROSS REVENUE CONVERSION FACTOR

In its Application, UI proposed Gross Revenue Conversion Factors of 1.826236, 1.818987, 1.818877 and 1.818521 for years 2006, 2007, 2008 and 2009, respectively. Schedule A-2.0 A-D. The Gross Revenue Conversion Factor is a calculation of the Company's allowed Return on Equity times the effects of the Connecticut Corporation Business Tax (CCBT), federal income taxes, gross earnings tax (GET) and uncollectibles. This calculation produces the amount of gross pre-tax and uncollectibles revenue required to satisfy the Company's after-tax and uncollectibles return on equity.

The OCC indicates that the Company's calculations include a CCBT factor that has a surcharge built in for each of the Rate Plan years. According to statute, there will be imposed a 20% surcharge in 2006 and a 15% surcharge in 2007. UI's calculations for 2008 and 2009 include the 15% surcharge on the assumption that the surcharge will continue, although no legislation currently exists to back up this assumption. The OCC recommends that UI's *pro forma* CCBT expense be reduced from UI's proposed 8.625% to the statutory rate of 7.5% in 2008 and 2009. OCC Brief, pp. 113 and 114.

The Department agrees with the OCC that the Gross Revenue Conversion Factor for 2008 and 2009 should include CCBT at the 7.5% statutory rate. Accordingly, the Department has recalculated the 2008 and 2009 Gross Revenue Conversion Factor as shown on UI's Schedule A-2.0 C and D as follows:

	2008 Rate Year	2009 Rate Year
Operating Revenue Percentage	100.000000%	100.000000%
Less: Connecticut Corporation Business Tax	7.500000%	7.500000%
	----	----
Operating revenue % after state taxes	92.500000%	92.500000%
Federal income tax rate	35.000000%	35.000000%
Federal income tax	32.375000%	32.375000%
	----	----
Operating income after federal income tax	60.125000%	60.125000%
Gross revenue conversion factor	1.663202	1.663202
Divided by 1 minus the weighted GET rate	93.149695%	93.149695%
	----	----
Gross revenue conversion factor including GET	1.785515	1.785515

Uncollectible factor	0.00586414	0.00568061
Divided by 1 minus the weighted GET rate	93.149695%	93.149695%
	——	——
Uncollectible factor including GET	0.00629539	0.00609837
Uncollectible factor including GET plus 1	1.00629539	1.00609837
Multiply by the gross revenue conversion factor Including GET	1.785515	1.785515
	——	——
Total Gross Revenue Conversion Factor	1.796756	1.796404

***76** Accordingly, the Department will use Gross Revenue Conversion Factors of 1.796756 and 1.796404 for 2008 and 2009, respectively, in its calculation of UI's revenue requirements.

H. COST OF CAPITAL/CAPITAL STRUCTURE

1. Introduction

The United States Supreme Court, in Federal Power Commission v. Hope Natural Gas Company, 320 US 591 (1944), established criteria to determine the cost of capital allowances. In its Decision, the Court determined that companies need to be allowed to earn a level of revenues sufficient to enable them to operate successfully, maintain their financial integrity and to attract capital and compensate their investors for their risk.

By Connecticut law, utilities are entitled to a level of revenues that will allow them '…to cover their operating and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection for the relevant public interests, both existing and foreseeable. ' Conn. Gen. Stat. §16-19e(a) (4).

To calculate a rate of return on rate base that is appropriate for UI's overall cost of capital, the Department first identifies the components of the Company's capital structure. The cost of each capital component is then determined and weighted according to its proportion of total capitalization. These weighted costs are summed to determine the Company's overall cost of capital, which becomes the allowed rate of return on rate base (ROR).

2. Capital Structure

The Company has proposed that a capital structure consisting of 52% equity and 48% debt be utilized for each year of the Rate Plan. At the time of filing the Application, UI's actual capital structure was approximately 48% equity and 52% debt. Response to Interrogatory EL-15. The Company expects to reach its proposed 52% equity ratio at the beginning of the four-year plan. Avera PFT, p. 5. The Company indicated that it will receive a $72.6 million equity contribution from UIL at the end of 2005, which will adjust its equity structure to approximately 52% as of December 31, 2005. Response to Interrogatory EL-18. The Company expects to continue to manage its allowed capital structure through its dividend payout strategy. This strategy is to dividend amounts to UIL to manage UI's proposed 52% equity capital structure over the plan period. Response to Interrogatories EL-26-1 and EL-27.

Based on such capital structure assumptions, the Company's proposed weighted average cost of capital [14] over the four-year plan is as follows:

***77** Source: Schedule D-1.0 D

In support of UI's proposed capital structure, the Company provided the projected average long-term capitalization indicating a 50.9% common equity ratio for the proxy group of electric companies as forecasted by Value Line for the period 2007-2009. Avera PFT, Exhibit WEA-1.

The OCC witness recommended a capital structure consisting of 50% long-term debt and 50% common equity. This is approximately half way between UI's December 31, 2004 capitalization and that proposed by the Company. The OCC's recommended cost of capital, including suggested cost rates is shown below. Woolridge PFT, pp. 9-11.

		Cost	Weighted
Class of Capital	Ratios	Rate	Cost Rate
Long-Term Debt	50.00%	4.24%	2.12%
Common Equity	50.00%	8.60%	4.30%
	____		____
	100.00%		6.42%

Source: Woolridge PFT, pp. 11 and 52.

The OCC witness states that the current median common equity ratio and returns on common equity for the proxy group employed by UI's witness are 41% and 9.6%, respectively. Woolridge PFT, p. 9. The OCC argues that the Company's proposed capitalization over the plan years deviates from industry standards in that it contains excessive common equity. The OCC witness states that the Company's capital structure is flawed since many of the companies in the proxy group employed by UI are not strictly in the electric transmission and distribution business. In addition, the Company's capital structure study is based on projected capitalization and not the current capital structures. OCC Brief, p. 15. The OCC's recommended capitalization still provides the Company with a significant equity cushion over the capitalization of the proxy groups and believes it is more reasonable. OCC Brief, p. 16.

As of the Company's last rate case, UI's currently allowed capital structure is 47% equity and 53% leverage. The Department agrees with the OCC that the Company's proposed equity capitalization of 52% is excessive and it deviates from current and projected average equity ratios of the proxy group. The Department does not find there is economic justification for increasing its equity ratio since rating agencies or investors would not advise or make such an adjustment in evaluating a company's capitalization and degree of financial risk. The Company stated that the rating agencies' assessment is of a broad array of quantitative and qualitative factors and they do not provide supporting calculations or analyses underlying their assessment of a particular utility. Response to Interrogatory EL-104. However, UI provided Moody's ratings methodology for global regulated electric utilities, dated March 2005, which indicates that UI's currently allowed equity of 47% is well within the threshold to maintain a ‘A/Baa‘ credit rating. Response to Attachment EL-104-2, p. 8, Figure 5.

***78** Additionally, the Department finds that the higher risk of the unregulated portion of UIL's business and the high dividend payout ratio is putting upward pressure on the level of common equity UI should be using. Since the percentage of common equity in the capital structure should be related to the amount of risk, the consolidated UIL Holdings should contain a higher percentage of common equity than the less risky regulated utility. The Company states that the financial burden placed on UI to support UIL's unprofitable, unregulated subsidiaries, should improve as UIL continues to monetize its unregulated investments. Nicholas PFT, p. 13.

In allowing a cost of capital, the Department finds it unreasonable to require ratepayers to assume the additional equity of a 52% equity structure in the cost of capital calculation. In this regard, the Department finds that increasing the equity ratio from 47% to 52% would dramatically increase the cost of capital thereby increasing costs to ratepayers, but would have no significant impact on improving debt ratings or lowering the cost of debt. Further, UI has not been advised by rating agencies that it needs to increase its equity position to 52%, nor is it guaranteed to improve its credit ratings by simply increasing UI's equity capitalization. Tr. 10/20/05, p. 1782. Although the Company forecasts an average 50% equity ratio, the Department notes that the current equity ratio for Dr. Avera's proxy group averaged 41% which indicates UI's current equity ratio of 47% is above the current average for the proxy group. However, given UI's small size and concerns brought on by its credit rating downgrade, the Department finds it is reasonable to increase its equity ratio to 48% to remain in the uppermost range of the referenced proxy group of other electric utilities. The Department, therefore, finds that a 48% equity proportion in UI's capital structure is fully adequate and should enable the Company greater access to the capital markets and financial flexibility.

3. Cost of Long-Term Debt

The Company's average forecasted long-term embedded cost of debt is expected to increase each year over the four-year plan. For years 2006 through 2009, the average forecasted long-term embedded cost of debt is estimated at 4.24%, 4.26%, 4.79% and 5.66%. Schedule D-3.0 A. The increase of the long-term embedded cost of debt for years 2007 through 2009 reflects the anticipated cost of forecasted replacement debt using a projected interest rate of 6%. Response to Interrogatory EL-31. UI's embedded cost of long-term debt is based on the use of a forecasted interest rate using the yields on five-year treasury bonds as a benchmark and what the normal spread is between UI's debt and five-year treasury bonds. Tr. 10/20/05, pp. 1783 and 1784. UI testified that the current market rate for a five-year issuance is probably slightly lower than the projected 6% interest rate. Tr. 10/20/05, p. 1785.

The OCC's witness, Dr. Woolridge proposed a long-term debt cost rate of 4.24% for the entire four-year plan period. It is Dr. Woolridge's opinion that long-term interest rate forecasts are not reliable or accurate and therefore there is no reason to employ such forecasts to estimate a future debt cost rate. Woolridge PFT, p. 10; OCC Brief, p. 14.

***79** The Department finds that based on UI's Order No. 1 compliance filing for the 12 months ended September 30, 2005, in Docket No. 76-03-07, *Investigation to Consider Rate Adjustment Procedures and Mechanisms Appropriate to Charge or Reimburse the Consumer for Changes in the Cost of Fossil Fuel and/or Purchased Gas for Electric and Gas Public Service Companies*, the Company shows that its embedded cost of debt was 4.20%. UI has testified that it is projected to increase to 4.24%, 4.26%, 4.79% and 5.66% for each year of the Rate Plan 2006 through 2009, respectively. The Department believes that the current cost of the replacement debt issuances should be higher than the actual embedded cost of debt of 4.20% as of September 30, 2005, but less than the Company's forecasted embedded cost of debt of 5.66% in 2009 using the current interest rates. The Department notes that the current market interest rates are in the 4.30% range for the five-year treasury bonds. The Department concurs with the OCC that it is difficult to accurately forecast long-term interest rates and the Department will not do so. The Department, however, finds it reasonable to allow a higher embedded cost of debt to include the cost of the projected replacement notes. The Department finds that the more appropriate rate for the three projected refinancings scheduled for 2007, 2008 and 2009 should be 5.4% based on the current five-year bond yield of 4.3% with a spread of 1.10%. Accordingly, the Department determines that 4.24%, 4.25%, 4.64% and 5.38% are reasonable actual embedded costs of debt for UI for the 2006, 2007, 2008 and 2009 Rate Plan period, respectively. These embedded costs of long-term debt shall reflect the scheduled debt refinancings at the current costs of 5.4% calculated by the Department.

4. Cost of Equity

Based on the testimony and evidence provided, it became clear that an in-depth review of UI's allowed return of 10.45%, established in 2001, was warranted in this proceeding. The Department found it necessary to make various adjustments to the cost of equity data submitted in order to improve its analytical quality. These adjustments, which were deemed reasonable, clearly supported a downward adjustment to the Company's return. UI has reduced its operating risk by divesting itself of generation. Capital cost rates are currently at their lowest levels in more than four decades with interest rates at a cyclical low not seen since the 1960s. While the short-term interest rates have increased, as the Company highlights, the yields on the long-term U.S. Treasuries have remained in the 4.0 to 4.5% range for most of the year. The current interest yields are below the levels that existed at the time of UI's last rate proceeding in 2002. The Company is clearly functioning in a lower interest environment, today, which has contributed to lower expected returns.

Therefore, in considering the arguments and analyses of the Parties and Intervenors, the Department has set UI's return on equity (ROE) at 9.60%, and adopts such return in this proceeding. The Department determines that such return is fair and reasonable, enabling the Company to operate properly and attract the necessary capital for expansion. The cost of equity component, which is a measure of the investor's expected return, is discussed as follows:

a. Introduction

***80** There are several methods commonly used to determine the appropriate cost of equity. The determination of the cost of equity in this proceeding focused largely on the discounted cash flow (DCF) proxy group method. The DCF evaluates future cash inflows (dividends and capital gains) investors expect to receive from a stock against the current market price investors pay for the stock. The discount rate that brings the present value of the cash flows exactly equal to the market price is the cost of equity. The Department generally relies on the DCF analysis but also considers other methods. Accordingly, material was also presented using the risk premium capital asset pricing model (CAPM) by the OCC and UI. The CAPM evaluates the cost of equity by determining first an appropriate risk free rate. To this rate it adds a beta (or the degree of co-movement of the security's rate of return with the market's rate of return) times the expected equity risk premium (the amount by which investors expect the future return on equities, in general, to exceed that on the riskless asset). The following is a summary of the positions of the parties and intervenors on the subject of cost of equity:

b. Company ROE Proposal

The Company's cost of equity testimony was prepared by Dr. William Avera, a financial consultant on behalf of UI. Based on Dr. Avera's analysis, he advocated an allowed ROE of 11.6%, including an additional upward adjustment to the ROE of 20 basis points for flotation costs associated with the new equity. Dr. Avera's testimony was based on various risk premium methods and DCF analysis of seventeen comparable (proxy group) utilities. Avera PFT. pp. 3 and 35. Using the DCF approach, Dr. Avera performed two calculations: 1) constant growth or sustainable growth rate formula, and 2) multi-stage DCF model. In addition, since no single method should be considered a reliable guide to investors' required rate of return, Dr. Avera applied the use of various risk premium methods, such as the realized-rate-of-return approach and the CAPM approach. Avera PFT, p. 58.

The Company's cost of capital analyses focused on a reference group of other electric utilities composed of those companies included by Value Line in their Electric Utilities (East) Industry group. Avera PFT, p. 43. Companies were eliminated from this group based on the following criteria: 1) utilities that are rated below investment grade (3 utilities eliminated), and 2) firms that are involved in a major merger or acquisition (3 firms eliminated). Dr. Avera's seventeen-member proxy group consists of CH Energy Group, Consolidated Edison, Constellation Energy, Dominion Resources, Dusquesne Light, Energy East Corp., First Energy Corp., FPL Group Inc., Green Mountain Power, Northeast Utilities, NSTAR, Pepco Holdings, PPL Corp., Progress Energy, SCANA, Southern Company, and UIL Holdings. Avera PFT, Exhibit WEA-1. These seventeen utilities in the proxy group employed by the Company reflect the risks and prospects associated with UI's jurisdictional utility operations. Avera PFT, pp. 43 and 44.

***81** After selecting the seventeen-member proxy group, an ROE was calculated using a DCF method. The standard DCF formula assumes that the price of a share of common stock is equal to the present value of the expected cash flows (*i.e.*, future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return, or the cost of equity. Avera PFT, p. 41. In other words, the cost of equity is the discount rate that will equate the current price of a share of stock with the present value of all expected future cash flows from the stock. In an effort to reduce the number of required estimates and computational difficulties, the general form of the DCF model was simplified to a constant growth form requiring the following assumptions:

• Constant growth rate for both dividends and earnings;

• Stable dividend payout ratio;

• Discount rate exceeding the growth rate;

• Constant growth rate for book value and price;

• Constant earned rate of return on book value;

• No sales of stock at a price above or below book value;

• Constant price/earnings ratio;

• Constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve; and

• All of the above extend to infinity.

Given these assumptions, the general form of the DCF model takes the constant growth form of:

$K^e = (D^1/P^0) + g$ Where:

K^e = Cost of equity

D^1 = Expected dividend per share in a period

P^0 = Current stock price

g = Long-term growth rate expectations

Dr. Avera states that when earnings are derived from stable activities, and earnings, dividends, and book value track fairly closely, the constant growth form of the DCF model offers a reasonable working approximation of stock valuation that provides useful insight as to investors' required rate of return. Avera PFT, pp. 42 and 43.

The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D1/P0) for the firm in question. Avera PFT, p. 45. Dr. Avera used estimated dividend payments of each proxy group utility over the next twelve months for 2006, obtained from Value Line, which served as D1. This projected annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. Based on recent stock prices from Value

Line an expected dividend yield averaged 4.2%. In addition, Dr. Avera calculated a second expected dividend yield of 4.5% based on the average price over the twelve months ended May 31,2005. Avera PFT, p. 46; Exhibit WEA-2.

The next step is to develop a growth rate (g) that reflects investors' growth expectations for the electric utilities. While Dr. Avera believes historical trends in electric utility dividends provide little guidance as to future expectations, he states that investors have recently expressed renewed interest in dividend payments. As such, Dr. Avera presented the dividend growth projections for each proxy group company reported by *Value Line* averaging 5.6%, and also calculated an implied growth rate based on Value Line's reported per share values for 2004 and their 2008-2010 forecast horizon of 4.8% for the proxy group average. Avera PFT, pp. 47 and 48. Dr. Avera states that investors' focus has shifted from dividends to earnings as a measure of long-term growth, as dividend payout ratios for the electric utility industry trended downward. Therefore, Dr. Avera also presented the earnings per share (EPS) growth projections reported by *Value Line, First Call, Zacks*, and *Reuters*. The average earnings growth rates for the proxy group ranged from 4.4% to 6.1%. Avera PFT, p. 49; Exhibit WEA-3. Dr. Avera reasons that the only relevant growth rate is the forward-looking expectations that are captured in current stock prices. Avera PFT, p. 51.

***82** Additionally, Dr. Avera also examined the relationships between retained earnings and earned rates of return as an indication of the sustainable growth investors might expect from the reinvestment of earnings within a firm. The sustainable growth rate is calculated by the formula, g = br + sv, where as 'b' is the expected retention ratio, 'r' is the expected earned return on equity, 's' is the common equity percentage expected to be issued annually as new common stock, and 'v' is the equity accretion rate. Dr. Avera calculated the average sustainable growth rate of 5.2% for the proxy group. Avera PFT, pp. 52 and 53; Exhibit WEA-4.

Combining the dividend yield range of 4.2% to 4.5% with the representative expected growth rate range of 4.4% to 6.1%, implied a constant growth DCF cost of equity range of 8.6% to 10.6%. Dr. Avera notes the short-term projected growth rates typically used to apply the DCF model do not necessarily capture investors' long-term expectations for the industry. Dr. Avera believes that the resulting cost of equity estimates derived from the DCF models will be downward-biased. Accordingly, he finds it unreasonable to establish an ROE based on this single DCF approach, therefore, he also applied a multi-stage DCF model to the proxy group. Avera PFT, p. 54.

Dr. Avera employed a multi-stage DCF model to the proxy group using a four and a half year holding period (2005-2009). Avera PFT, p. 55. Dr. Avera testified to using a mid-year convention formula that assumes cash flow occurs in mid-year instead of the end of the period. Tr. 10/20/05, p. 1802. For each proxy group company, Dr. Avera applied *Value Line's* projected dividend over the next four and a half years as future cash flows and projected a stock price at the end of the four and a half years. To project a future stock price for each proxy group company, he used *Value Line's* projected earnings per share for the years 2008 to 2010 and multiplied that to the current P/E ratio. Tr. 10/20/05, pp. 1805 and 1806. Dr. Avera attested to using *Value Line* EPS estimates, but imputed his own projected stock price for the years 2008-2010. Tr. 10/20/05, pp. 1808-1810. The cost of equity estimates produced by Dr. Avera's application of the multi-stage DCF model averaged 10.6%. Avera PFT, p. 56; Exhibit WEA-5.

Since no single method should be considered a reliable guide to investors' required rate of return, Dr. Avera also evaluated the cost of equity for UI using various applications of the risk premium method. Dr. Avera based his estimates of equity risk premiums for electric utilities on (1) surveys of previously authorized rates of ROE, (2) realized rate of return, and (3) alternative applications of the CAPM. The risk premium method estimates the cost of equity by determining the additional return investors require to forgo the relative stability of bonds and to bear the greater risks associated with common stock, and then adding this equity risk premium to the current yield on bonds. Avera PFT, p. 57. Dr. Avera uses the 20-year Treasury rate as well as the Moody's BBB public utility bond rate as the base yield in his various risk premium methods.

***83** First, Dr. Avera evaluated surveys of previously authorized ROE's which are frequently referenced as the basis for estimating equity risk premiums. The ROE's authorized utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates (RRA) and published in its Regulatory Focus report. Dr. Avera assessed the average allowed ROE's for electric utilities to calculate equity risk premiums over a 31-year period which averaged 3.17%, and the public utility bond yields averaged 9.59%. Avera PFT, pp. 58-61; Exhibit WEA-6. Before implementing the risk premium method, Dr. Avera made adjustments to the equity risk premium to incorporate the inverse relationship since the current interest rate levels have changed since the equity risk premiums were estimated. The yield on average public utility bonds in May 2005 was 5.60%, which implied a current equity risk premium of 4.89% for electric utilities. Adding the May 2005 yield on BBB public utility bonds of 5.88% to the implied current equity risk premium of 4.89%, produces a current cost of equity of 10.77%. *Id.* In addition, Dr. Avera incorporated a forecasted yield for 2006-2009 and adjusted for changes in interest rates since the study period implied an equity risk premium of 4.29%. Adding this forecasted equity risk premium of 4.29% to the May 2005 yield on BBB public utility bonds for the 2006-2009 period of 7.2% resulted in an implied cost of equity of 11.49%. Avera PFT, p. 62.

Under the realized-rate-of-return (RRR) approach, equity risk premiums are calculated by measuring the rate of return (including interest, dividends, and capital gains/losses) actually realized on an investment in common stocks and bonds over historical periods. The realized rate of return on bonds is then subtracted from the return earned on common stocks to measure equity risk premiums. Avera PFT, p. 58. Dr. Avera computed the equity risk premium as the historic arithmetic mean difference between stock price and bond returns over a 58-year period, 1946 through 2004, averaging 3.99%. Adding this 3.99% equity risk premium to May 2005 yield of 5.88% on BBB public utility bonds produces a current cost of equity of 9.87%. Avera PFT, p. 62. Also, Dr. Avera added this equity risk premium of 3.99% to the forecasted 7.2% yield on BBB utility bonds for 2006-2009, implying a forecasted cost of equity of 11.19%. Avera PFT, p. 63; Exhibit WEA-7.

The CAPM approach measures the market-expected return for a security as the sum of a risk-free rate and a risk premium based on the portion of a security's risk that cannot be eliminated by holding a well-diversified portfolio. Under the CAPM, risk is represented by the beta coefficient (B), which measures the volatility of a security's price relative to the market as a whole. Avera PFT, p. 58. The basic formula for the CAPM is as follows:

$K = R^{f} + B\,(R^{m} — R^{f})$ where:

***84** K = required rate of return

R^{f} = risk-free rate

R^{m} = expected return on market portfolio

B = beta, or systematic risk, for stock

Dr. Avera applied the CAPM to the proxy group using market risk premiums (Rm — Rf) based on 1) forward-looking estimates of investors' required rates of return and 2) historical realized rates of return.

Dr. Avera's CAPM-Forward approach uses a forward-looking market equity risk premium which he computed to be 9.3% by subtracting a risk-free rate of 4.6% based on the May 2005 average yield on 20-year Treasury bonds from an expected annual return for the S&P 500 of 13.9% (13.9% - 4.6% = 9.3%). He computed an expected return of 13.9% for the firms in the S&P 500 using a dividend yield of 1.8% and an average projected EPS growth rate of 12.1%. The growth rate represents the expected EPS growth rates over the next five years as provided by IBES for the stocks in the S&P 500. Multiplying this market equity risk premium of 9.3% by the average Value Line beta of 0.79 for the proxy group, and then adding the resulting 7.3% risk premium (9.3% X 0.79 beta = 7.3%) to the 4.6% May 2005 average 20-year Treasury bond yield (risk-free rate), produces a current cost of equity of 11.9%. Avera PFT, p. 64; Exhibit WEA-8. In addition, Dr. Avera incorporated a 6% forecasted yield on 20-year Treasury bond for the 2006-2009 horizon, published by EIA, GlobalInsight and Blue Chip, resulting in a market risk premium of 7.9%. Once again multiply the 7.9% market risk premium by the 0.79 beta, and then add the resulting 6.2% risk premium to the 6.0% forecasted risk-free rate for 2006, results in an implied cost of equity of 12.2%. *Id.*

Dr. Avera's CAPM-Historic used the historical arithmetic mean realized rate of return on the S&P 500 of 7.2% as reported by *2005 Yearbook, Valuation Edition, Ibbotson Associates*, over the period 1926 through 2004. Multiplying this 7.2% historical market risk premium by the 0.79 average Value Line beta produced an equity risk premium of 5.7% for the proxy group. Adding this 5.7% equity risk premium to the 4.6% risk-free rate, resulted in an implied cost of equity of 10.3%. Avera PFT, p. 65. After incorporating a 6% projected bond yield for 2006-2009, this application of the CAPM based on historical realized rates of return implied a cost of equity of 11.7%. Avera PFT, p. 66; Exhibit WEA-9.

The CAPM model, like the DCF approach, is an ex-ante, or forward-looking model based on expectations of the future. Since the historical approach does not incorporate forward-looking estimates, Dr. Avera gave it less weight in arriving at his recommended ROE. Based on the results of Dr. Avera's analyses and assessments of the relative strengths and weaknesses inherent in each method, he concluded that the cost of equity for the proxy group is in the 10.9% to 11.9% range, excluding an adjustment for flotation costs. Avera PFT, p. 67.

Summary of Dr. Avera's Cost of Equity Approaches and Results

6p								
Approach	**Results:**							
	Current	**Forecast**						
6p								
DCF —DCF — constant growth	8.6% to 10.6%							
6p								
Risk Premium —Authorized Returns	10.77%	11.49% —Realized Rate of Return — Historic	9.87%	11.19% —CAPM — Forward	11.9%	12.2% —CAPM — Historic	10.3%	11.7%
6p								
Flotation Costs		20 bp						
6p								
Recommended Cost of Equity		11.6%						

c. Position of Parties

***85** The OCC's witness cost of equity recommendation in this proceeding was 8.60% based on the capital structure containing 50%/50% capitalization and an overall fair rate of return of 6.43% for Rate Plan years 2006 through 2009. The OCC's cost of equity witness, Dr. Woolridge, employed the use of the DCF and CAPM approaches to two groups of electric utility companies.

Dr. Woolridge established two proxy groups on which he evaluated the return requirements of investors. His primary proxy group, Group B, is a subset of the group of seventeen companies employed by UI. Dr. Woolridge screened Dr. Avera's seventeen-member proxy group to include only companies that 1) receive at least 60% of revenues from regulated electric utility service (this eliminated five companies), and 2) operate primarily in the eighteen states that have enacted some form of deregulation for electric utility service (this eliminated four more utilities). The resulting group, Group A, includes eight electric utility companies which is comprised of: Consolidated Edison, Dusquesne Light, FirstEnergy, Northeast Utilities, NSTAR, Pepco Holdings, PPL Corp., and UIL Holdings. Woolridge PFT, p. 8; Exhibit JRW-3. Dr. Woolridge states that both proxy groups are larger than UI in terms of average revenues and net plant.

Dr. Woolridge primarily focused on the DCF model and applied it to both sets of proxy groups to estimate the cost of equity. He believes that the DCF model provides the best measure of equity cost rates for public utilities. Woolridge PFT, p. 17. He states that virtually all investment firms use some form of DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model (DDM). The DDM is based on the presumption that a company's dividend payout progresses initially through a growth stage, then continues through a transition stage and finally assumes a steady state stage. Dr. Woolridge believes that the dividend payment stage of any particular company is dependent on the profitability of its internal investments, which is, for the most part, a function of the life cycle of the product or service. In using this model to estimate a firm's cost of equity capital, Dr. Woolridge stated that dividends are projected into the future applying the different growth rates in these three stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the common stock price. Woolridge PFT, pp. 18 and 19.

Dr. Woolridge used the constant growth version of the DCF model believing that public utilities are in the steady-state stage of the three stage DCF given the regulated status of public utilities since returns are set through the ratemaking process. Woolridge PFT, p. 20. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. He developed dividend yields on the common stock prices for the companies in his proxy Group A and the same proxy Group B employed by UI for the six-month period ending September, 2005. Woolridge PFT, Exhibit JRW-7. For the DCF dividend yields for the two proxy groups, Dr. Woolridge used the average of the six-month period and September, 2005 dividend yields which were 4.4% and 4.15% for Groups A and B, respectively. Woolridge PFT, pp. 21 and 22.

***86** According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. Dr. Woolridge states that it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate. The appropriate adjustment to the dividend yield is complicated in the regulatory process when the overall cost of capital is applied to a projected or end of future test year rate base. The net effect of this application is an overstatement of the equity cost rate derived from the DCF model. This overstatement results from applying an equity cost rate calculated using current market data to a future or test year end rate base which includes growth associated with the retention of earnings during the year. Due to these difficulties, Dr. Woolridge adjusted the dividend yield by half the expected growth so as to reflect growth over the coming year. Woolridge PFT, pp. 22 and 23.

For the growth component of his DCF calculation, Dr. Woolridge used a combination of historic and projected growth rates for earnings and dividends per share and for internal or book value growth to assess long-term potential. He calculated historic growth rates in EPS, dividends per share (DPS), and book value per share (BVPS) for the two proxy groups. He evaluated Value Line's historic and projected growth rate estimates for EPS, DPS and BVPS. In addition, he used earnings growth rate forecasts as provided by Zacks, Reuters, and First Call which solicit five-year earnings growth rate projections from securities analysts and compile the averages of these forecasts on a monthly basis. Finally, Dr. Woolridge also assessed prospective growth as measured by prospective earnings rates and earned returns on common equity. Woolridge PFT, p. 24.

First, Dr. Woolridge observed the historic growth rates in EPS, DPS and BVPS for the two proxy group companies, as published in the Value Line Investment Survey. Due to the presence of outliers among the historic growth rate figures he used both the means and medians in his analysis of the data. Woolridge PFT, p. 25. As measured by the means and medians, historic growth in EPS, DPS, and BVPS for proxy Group A ranged from -0.8% to 6.8%, with an average of 1.1%, and for proxy Group B it ranged from -0.9% to 4.5%, with an average of 2.2%. Woolridge PFT, Exhibit JRW-7, p. 3, Panel I. Also, he found Value Line projections of EPS, DPS and BVPS growth for the time period 2002-2004 to 2008-2010 to be 4.2% for proxy Group A and 4.7% for proxy Group B using the average of the means and medians. Woolridge PFT, Exhibit JRW-7, p. 4, Panel II. Dr. Woolridge calculated prospective internal growth for both proxy groups from Value Line's average projected retention rate and return on shareholders' equity. The average of the mean and median data for prospective internal growth rate was 4.3% for proxy Group A and 4.5% for proxy Group B. *Id.*

Dr. Woolridge used Zacks, First Call, and Reuters data which is a collection and summarization of published Wall Street analysts' projected five-year EPS growth rate forecasts for companies. He averaged the expected five-year EPS growth rates from these three services for each proxy group company to arrive at an expected EPS growth rate for each company. For proxy Groups A and B, the average projected five-year EPS growth rates are 3.9% and 4.7%, respectively. Woolridge PFT, p. 26.

***87** To derive the overall growth rate for the two proxy groups, Dr. Woolridge used all of the data that he collected. He acknowledges that the projected growths for the proxy groups is higher. Given the average historic and projected growth rate figures for each proxy group, Dr. Woolridge gave greater weight to the projected growth figures and assumed an appropriate expected DCF growth rate of 4.0% for proxy Group A, and an expected DCF growth rate of 4.5% for proxy Group B. Woolridge PFT, p. 27.

Combining all the components of the DCF model, Dr. Woolridge calculated an equity cost rate of 8.49% for proxy Group A and cost of equity of 8.74% for Group B. The details underlying the cost of equity for proxy Group A include a combined dividend yield of 4.4%, a growth adjustment to the yield of 1.0200 and a growth rate of 4% equaling 8.49% DCF cost of equity. The results of the 8.74% equity cost rate for proxy Group B include the combination of a 4.15% dividend yield with a growth adjustment of 1.0225 plus the DCF growth rate of 4.5%.

Dr. Woolridge also employed the CAPM using the two proxy groups. To determine an equity cost rate using the CAPM, there are three inputs: 1) the risk-free rate of interest, 2) beta (the systematic risk measure), and 3) the equity or market risk premium. The yield on long-term Treasury bonds is viewed as the risk-free rate of interest in the CAPM and is readily observable in the markets. Woolridge PFT, p.30. In recent years, Dr. Woolridge observed the yield on 10-year Treasury bonds replace the yield on 30-year Treasury bonds as the benchmark long-term Treasury rate. As of September 19, 2005, the yield on the 10-year and 30-year Treasuries were 4.26% and 4.55%, respectively. Dr. Woolridge elected to use 4.5% as the risk-free rate. Woolridge PFT, p. 32.

Dr. Woolridge stated that beta, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historic betas due to their tendency to regress to 1.0 over time. OCC Brief, p. 19. A stock with below average price movement, such as that of a regulated utility, is less risky than the market and has a beta of less than 1.0. Dr. Woolridge employed the average beta for both proxy groups of 0.79 as provided in the Value Line Investment Survey. Woolridge PFT, p. 34; Exhibit JRW-8, p. 2.

The most difficult part of the CAPM is to measure the expected equity or market risk premium. The equity risk premium is the expected return on the stock market minus the risk-free interest rate. Woolridge PFT, p. 34. As such, it is the difference in the expected total return between investing in equities and investing in stable fixed-income assets, such as long-term government bonds. Dr. Woolridge cited three ways to measure the equity risk premium:

• *Historic Ex Post Returns* — the traditional way to measure the equity risk premium was to use the difference between historic average stock and bond returns.

***88** • *Surveys* — an alternative approach to estimating an equity risk premium is through the use of surveys of investors and financial professionals.

• *Ex Ante Models and Market Data* — these studies compute *ex ante* expected returns using market data such as expected earnings and dividends to arrive at an expected equity risk premium.

Dr. Woolridge used an *ex ante* or forward-looking equity risk premium of 4.16%. Woolridge PFT, p. 47; Exhibit JRW-8, p. 3. To arrive at this figure, Dr. Woolridge evaluated the results of eighteen equity risk premium studies performed in recent years which include: 1) the annual study of historic risk premiums as provided by Ibbotson Associates, 2) *ex ante* equity risk premium studies commissioned by the Social Security Administration, 3) equity risk premium surveys of CFOs, Financial Forecasters, as well as academics, 4) Building Block approaches to the equity risk premium, and 5) other miscellaneous studies. The overall average equity risk premium of these studies is 4.16% which was employed in Dr. Woolridge's CAPM. Using the inputs discussed above (4.5% risk-free rate X 0.79 beta + 4.16% equity risk premium), Dr. Woolridge arrived at a CAPM equity cost rate of 7.8% for the two proxy groups.

Given his DCF and CAPM equity cost rate results, Dr. Woolridge concluded that a fair equity cost rate for UI is 8.6%. Although Dr. Woolridge agrees that this figure is low by historic standards, he argues that it is appropriate given that 1) interest rates are at a cyclical low not seen since the 1960s, 2) the 2003 tax law reduces the tax rates on dividend income and capital gains which lowers the pre-tax return required by investors, and 3) the decline in the equity risk premium.

5p

Summary of Dr. Woolridge's Cost of Equity Approaches and Results

Approach	**Proxy Group**	**Result**		
DCF —DCF — Constant Growth	Group A	8.49% —DCF — Constant Growth	Group B	8.74%
Risk Premium —CAPM	Groups A & B	7.8%		
Recommended Cost of Equity		8.6%		

5p

d. Cost of Equity Analysis

***89** The Department assessed the testimonies and recommendations of Dr. Avera and Dr. Woolridge and is confident that the best solution to UI's cost of equity capital requirements exists within the framework of the DCF model.

1. Analysis of the Company's DCF Proposal

To test the results of the UI and the OCC witnesses, the Department conducted its own cost of equity analysis using both the DCF and risk premium methodologies. The Department relied on both of these methodologies because of their acceptance in the field of cost of equity analysis and in an effort to take into account the differing approaches to estimating the cost of equity.

With regard to the choice of a proxy group, the Department considered the proxy group employed by the Company's witness and the proxy groups derived by the OCC witness, and made adjustments. The Department found several companies that had excessive unregulated operations, such as Constellation Energy, whose makeup was different enough from UI and the rest of the proxy group to exclude it. The Company's ROE witness stated during the hearing that the regulated utility sector has lower betas and are generally perceived as less risky than the competitive sector. Tr. 10/20/05, p. 1792. This indicates that unregulated operations would indeed have a higher beta, or risk factor than regulated activities. Since more risk implies a higher desired return from investors, this fact alone contributed to an upward bias in the cost of equity result calculated by the proxy group. Consistent with the criteria established in prior rate cases for UI and CL&P, the Department chose to eliminate those companies that received less than 60% of their operating revenues from regulated electric utility services or more than 40% of their operating revenues from unregulated non-utility affiliates. The Department's objective was to produce a proxy group whose predominant source of revenue is derived from regulated electric utility service. Those companies with significant amounts of unregulated or non-electric activities were: CH Energy Group, Constellation Energy, Dominion Resources, Energy East, and SCANA. Therefore, a twelve-member proxy group was employed for the purposes of the Department's analysis. The exclusion of companies owning significant amounts of unregulated operations from the proxy group had the effect, all else equal, of lowering the ROE. Also, the Department notes that non-utility or unregulated activities do not fit the constant growth assumptions of the DCF model as well as regulated activities do.

After selecting the twelve-member proxy group, the first step in the DCF is to calculate the average dividend yield. Dr. Avera used estimated dividend payments to project an annual dividend and then divided it by the corresponding stock price for each of his proxy group companies to derive at a dividend yield range of 4.2% to 4.5%. Based on recent stock prices from Value Line, dated June 3, 2005, for the twelve-member proxy group, the Department calculated a dividend yield of 4.4%.

***90** Next step is the calculation of long-term earnings per share growth rates. Dr. Avera's heavy reliance on projected EPS growth rates with the Company's proxy group was the subject of considerable controversy. Although Dr. Avera presented the dividend growth projections for each of the Company's proxy group members as reported by Value Line, he dismissed these measures believing that investors' focus has shifted from dividends to earnings as a measure of long-term growth. The Department recognizes that Dr. Avera relied exclusively on earnings growth rate projections published by five analyst services to get as reliable as possible a consensus estimate of long-term growth based on earnings. However, it relies solely on projected earnings information and makes no attempt to represent the anticipated growth rate in dividends per share, book value per share, or stock price. The OCC witness argues that reliance on forecast growth rates alone, ignoring all other indicators of expected growth, especially historic growth, produces an upwardly biased or overstated projected growth rate range.

First, the Department applied Dr. Avera's projected earnings growth rates as presented by the five analyst services, to the Department's twelve-member proxy group. Using the same EPS growth projections that were supplied by Dr. Avera, resulted an average earnings growth rate in the range of 3.8% to 5.7%, for an average growth rate of 4.5%. Combining the adjusted dividend yield of 4.4% with the average expected growth rate of 4.5%, implied a DCF cost of equity of 8.9%. Secondly, the Department examined Dr. Avera's sustainable growth rate analysis and found that it produced higher sustainable growth rates than Value Line's own projected annual growth in BVPS. The Department finds the Company's estimate of the average sustainable growth rate to be overstated. Using Value Line's own forecasted annual growth rates and applying this to the Department's twelve-member proxy group, produced an average sustainable growth rate of 4%. Again, combining the adjusted dividend yield of 4.4% with the representative growth rate range of 4% to 4.5%, implied a constant growth DCF cost of equity range of 8.4% to 8.9% for the twelve-member proxy group.

Additionally, the Department assessed Dr. Avera's multi-stage DCF model before determining the appropriate cost of equity for UI. The Department's main concern with Dr. Avera's multi-stage DCF approach is his calculation of the projected stock prices for the proxy group. The OCC argues that Dr. Avera's inflated estimate of the expected future stock price grossly overstates the proxy group's equity cost rate and invalidates Dr. Avera's multi-stage DCF approach. Woolridge PFT. pp. 66 and 67. Dr. Avera used Value Line EPS estimates, but imputed a projected stock price for the years 2008-2010 that is much higher than Value Line's own forecasted future stock price. The Department applied Value Line's own projected future stock prices for each of the twelve proxy group companies into the multi-stage DCF model. These adjustments to the multi-stage DCF model produced a cost of equity of 9.64% for the twelve-member proxy group.

***91** The need for a downward adjustment to the Company's ROE was evident in evaluating UI's regulated business against the proxy group DCF. In this regard, each of the proxy group companies contained both regulated and unregulated operations, therefore a general risk profile that was greater, and requiring a higher return, than UI's regulated operations. Since the charge of this proceeding was to determine the return for UI's regulated operations, the proxy group results overstate this return however, the Department has made no adjustment in its DCF calculation.

In addition to the twelve-member proxy group analysis, the Department also calculated the DCF analysis for UIL individually based on its own dividend yield and growth expectations. Dr. Avera's constant growth DCF analysis indicated a DCF cost of equity for UIL of approximately 6.5% to 6.8% based on an implied dividend yield of 5.5% (recent price) to 5.8% (12 month average) plus the average expected growth rate of 1.0%. Exhibits WEA-2 and WEA-3. UIL's projected earnings growth was 1.0% compared to average growth rate range of 4.4% to 6.1% for his proxy group. In addition, Dr. Avera provided a multi-stage DCF model which calculated UIL's cost of equity to be 4.3%. Exhibit WEA-5.

The reliance on forecast growth rates alone, absent an examination of all the underlying determinant of long-run dividend growth, gives no consideration to actual past earnings performance and will produce inaccurate DCF results. Although the Department finds considerable evidence supporting both historical and forecasted growth rates, a careful examination was made of the Company's earnings growth forecasts and adjustments were made accordingly as discussed above. The adjusted DCF models cost of equity resulted in a range of 8.4% to 9.64% for the twelve-member proxy group. The Department finds that Dr. Avera's final recommended cost of equity range for UI of 10.9% to 11.9% for his proxy group was too high and not fully supported by his testimony. It essentially ignores his own DCF results of 8.6% to 10.6%, a considerable part of his analysis and which presented a range below even the bottom of Dr. Avera's recommended 10.9%-11.9%. The Department has consistently relied on the DCF in its determination of an appropriate cost of equity. Finally, the justification for Dr. Avera's final recommended range was not mathematically supported as the Company witness himself testified that this range was not calculated, but developed judgmentally. Tr. 10/20/05, pp. 1819-1821.

2. Analysis of OCC's DCF Proposal

Before determining the appropriate cost of equity for the Company, the Department also assessed the analyses of the OCC's cost of capital witness, Dr. Woolridge. The Department finds that Dr. Woolridge's constant growth version of the DCF model is a reasonable approach to measuring that which investors expect to receive. Although Dr. Woolridge gave greater weight to the projected growth rates in his DCF analysis, he considered the historic growth rates in EPS, DPS and BVPS, as well, to derive the overall growth rate for his two proxy group companies. The Department applied the components of Dr. Woolridge's DCF model to the selected twelve-member proxy group. This resulted in a DCF cost of equity of 8.65% which included a 4.29% average dividend yield with a growth adjustment of 1.022 plus the combined average of Value Line's historic and projected growth rates of 4.27%. The Department finds the resultant 8.65% DCF cost of equity appropriate and it falls within Dr. Woolridge's range of 8.49% for his proxy Group A and 8.74% for proxy Group B.

***92** *3. Analysis of the Risk Premium Methodology*

With regard to the Company's approach to the risk premium methods, some problems quantifying the risk premiums were identified by the OCC. First, Dr. Avera used a forecasted 20-year Treasury rate of 5.7% and BBB public utility bond rate of 7.2% for his base yield in his various risk premium approaches. However, as the OCC provided, as of September, 2005, the 20-year Treasury rate was only 4.52% and the BBB bond rate was only 5.69%. Woolridge PFT, p. 69; OCC Brief, p. 28. As of October 20, 2005, the 20-year Treasury rate of 4.78% was provided during the hearing. As a result, the base yields of Dr. Avera's various risk premium analyses are inflated and his estimated equity cost rates are overstated. The Department agrees with the OCC witness, that given the uncertainty over the economy and interest rates, the Company should be employing the current Treasury rates and public utility bond yields in the risk premium analyses.

Secondly, the OCC argues that Dr. Avera employs excessive risk premium estimates in his various risk premium approaches. In his historic approaches of the CAPM and RRR, Dr. Avera used historic returns over long-term periods to compute an expected market risk premium. As the OCC witness points out, market conditions are different today and the historic equity risk premium methodology is unrealistic in that it makes the explicit assumptions that risk premiums do not change over time based on market conditions such as inflation, interest rates, and expected economic growth. Dr. Avera also employed a forward approach of the CAPM which he computes this expected risk premium as the difference between a prospective DCF-derived overall market return of 13.9% (using dividend yield and growth rates for the S&P 500) and a risk-free rate of 4.6%. Dr. Woolridge argues that his expected market return is out of line with historic norms and is inconsistent with current market conditions. OCC Brief, p. 30.

The objective of using any cost of equity model should be to enhance the accuracy of the final result. The range of estimates between the various risk premium methods of Dr. Avera and Dr. Woolridge range roughly 200 to 500 basis points, based on using different time periods for its measurement, and the many interpretations of how it may be measured (geometric versus arithmetic), it is reasonable to conclude that the risk premium approach suffers from so much subjectivity that it can be essentially used to produce whatever outcome is desired. Comparing the testimonies of the two cost of capital witnesses, it is evident that the interpretation of the risk premium data and the implementation of a risk premium study is subjective, requiring a great amount of professional judgment.

The Department finds Dr. Avera's range of 11.49% to 12.2% risk premium cost of equity results are overstated because of using projected interest rates and excessively high growth rates. However, the Department finds that Dr. Avera's risk premium approaches using the current interest rates which produced a cost of equity range of 9.87% to 10.77%, excluding his forward-looking CAPM models, is a much more reasonable approach to determining an appropriate cost of equity. Although, Dr. Avera stated that he primarily relied on his risk premium conclusions deriving the Company's final ROE recommendation, it is unclear as to how or if he incorporated the current period results of his risk premium approaches into his 11.6% recommended ROE. It is evident that Dr. Avera's risk premium ranges of 9.87% to 10.77% using the current interest rates is well below his recommended ROE range of 10.9% to 11.9%. In addition, the Department also evaluated the risk premium analyses of the OCC witness and believes Dr. Woolridge's 7.8% cost of equity using the CAPM method is understated due primarily to a low equity risk premium.

***93** For all the reasons discussed above, and absent any attempt to transform historic risk premium data into meaningful forward-looking estimate, the Department has evaluated the results of the risk premium analyses, however, places greater emphasis upon the DCF analyses and less upon risk premium results. Nevertheless, the Department employed a CAPM using the current interest rate, the average beta for the twelve-member proxy group, and the arithmetic mean return from 1926 to 2004 on Large Company Stocks as reported by Ibbotson Associates. The Department used the Ibbotson's large company arithmetic mean total return as opposed to the long-horizon equity risk premium as employed by Dr. Avera. The underlying details are shown below.

Consistent with prior rate case decisions, the Department estimated a CAPM cost of equity using the standard formula K=Rf + B(Rm — Rf). This calculation utilized an estimated risk free rate (Rf) of 4.78% (current interest rate on 20-year Treasury bonds as of 10/20/05), the proxy beta (B) of 0.76 (average beta for twelve-member proxy group), and the arithmetic mean return from 1926 to 2004 on Large Company Stocks (Rm) of 12.4%. Exhibit WEA-9, p. 1. Accordingly, the Department calculated the cost of equity under the CAPM approach to be 10.57% [4.78% + 0.76 (12.4% - 4.78%)].

The Department notes that the primary factor that results in a high cost of equity under the CAPM is the total return on large company stocks which has averaged 12.4% over the 78 year period. Given the lower returns over the past five years, expectations of shareholders, however, are less today than the long-term average. The Company's own expected return on pension assets was 8.0%. Therefore, the Department considers the CAPM results to be the upper bound of a reasonable cost of equity.

4. Flotation Costs

The Department considered the Company's recommendation for a return for its selling and issuance costs. The Company is requesting 20 basis points for flotation costs. The Company's witness established a flotation cost adjustment based on surveys of the financial literature and recent data from Morgan Stanley which suggest an average flotation cost percentage in the range of 3.6% to 10%. Avera PFT, pp. 69-72. Applying these percentages to Dr. Avera's representative dividend yield for his proxy group of 4.4% resulted in an implied flotation cost adjustment on the range of 16 to 44 basis points. From this range, Dr. Avera recommended a flotation cost adjustment of 20 basis points, which he believes is consistent with the Department's findings in the 03-07-02 Decision. Response to Interrogatory EL-110.

The OCC states that flotation costs are one-time expenses which are incurred when a Company sells additional stock. They are not a recurring annual item. Furthermore, the OCC points out that UI has not even indicated if it intends to sell additional shares to investors. Dr. Woolridge believes that flotation costs should be accounted for and added to the Company's rate request just like other expenses. Woolridge PFT, p. 58.

***94** To determine the flotation cost adjustment for UI, the Department considered the standard formula as referenced by a FERC ruling of K=f*s/(1+s) then the result would be amortized over the four-year Rate Plan. UI stated that it could require total financing of $175 million to support its capital expenditure program. Nicholas PFT, p. 9. UI estimated approximately $73 million of equity financing and the remainder in debt financing. Assuming the capital expenditure program will be financed by approximately 48% debt and 52% equity, a $73 million equity offering will represent about 16.8% of UI's existing equity ($73M/$435M — using 2006 equity from Schedule F-3.0). The industry average flotation costs as a percentage of the offering price of 3.6% was referenced by recent data from Morgan Stanley. Accordingly, K=3.6%*16.8%/ (1+16.8), or 52 basis points. Amortized over 4 years, this would amount to about 13 basis points to the cost of equity.

The Department notes that the flotation cost adjustment of 13 basis points incorrectly assumes that the Company's equity is reissued every year and none of the equity is raised through the retention of earnings. This amount has not been adjusted downward to reflect the capital contributions that would be made by the parent company, UIL, into UI in early 2006. Therefore, the Department finds it reasonable to make some adjustment to the Company's proposed flotation costs of 20 basis points and a downward adjustment to the 13 basis points as calculated using the FERC formula. Given these findings, the Department finds it reasonable to allow 10 basis points for flotation costs in UI's cost of equity.

5. Financial Condition

The Department analyzed a considerable breadth of information presented in this proceeding in order to determine the appropriate return on equity to allow UI. The Department was unable to substantiate maintaining the Company's currently allowed ROE of 10.45%, much less increase the ROE as proposed by UI. This was attributable to both the technical analysis and a variety of changes in key factors surrounding the financial setting of such ROE. Several important factors exist which support a lower allowed return at this time. Some of these factors included: 1) lower capital cost rates since UI's last rate case, 2) business risk has declined attributable to the Company receiving guaranteed returns on its CTA assets since 2000, 3) RRA returns have declined considerably since the last rate proceeding, 4) the effect of unregulated operations in the proxy group, 5) the Department's recent authorized ROEs, and 6) the tax on corporate dividends is now capped at 15% and the long-term capital gains have been reduced from 20% to 15%. The Company, however, did not explicitly consider these factors in its analysis. A discussion of these and other items is as follows:

First, capital cost rates for U.S. corporations are currently at their lowest levels in more than four decades. Corporate capital costs rates are determined by the level of interest rates and the risk premium demanded by investors to buy the debt and equity capital of corporate issuers. The benchmark for long-term capital costs in the U.S. economy is indicated by the rates on long-term U.S. Treasury bonds. At the time of UI's last rate setting proceeding, yields on 20-year treasury bonds were 5.25%. 01-10-10 Decision, p. 24. As provided in the October 20, 2005 hearing, the current 20-year treasury yield is about 4.78%. This implies a lower cost of equity for this proceeding. Lower interest rates are taken into account in the expected rate of return of investors in the DCF analysis and in the risk premium methods (risk premium/ CAPM).

***95** Second, UI's risk has also declined significantly since electric restructuring. By year-end 2002, UI shed its remaining interests in its nuclear assets. In general, a distribution-only company has less risk than a vertically-integrated utility because it would not be subject to operational failures, uncertain costs of operation and prudence reviews that comprise the generation business. Risk is also reduced since a higher portion of distribution costs are collected through fixed charges, such as the CTA rate base. In fact, risk is eliminated for the CTA rate base since the CTA revenues and costs are trued-up at the end of each year. While the Company had brought out the fact that the CTA assets are reduced over the last rate order, it still remains substantial, with a rate base of $242 million compared to a distribution rate base of approximately $400 million, UI still enjoys in essence a guaranteed return for the Company on the CTA assets.

Third, based on the first six months of 2005, the national average electric equity return authorization by state commissions was 10.36% as reported by the Regulatory Research Associates, Inc (RRA). At the time of UI's last rate proceeding, RRA's published ROE's granted by other Commissions for electric utilities averaged around 11.16%, and the Department granted an ROE of 10.45% for UI. The electric utility return on equity allowances granted by Commissions have declined considerably, representing an 80 basis point (11.16%-10.36%) decline from 2002 to the current date. This average tends to lag the most recently allowed returns since all companies do not have a rate case each year. Given the current financial situation and returns allowed by this Department, the Department believes that the average may still be declining. The Department also notes that the national average electric equity return would include those vertically integrated utilities that would hold a higher general risk profile than UI, thus driving the average ROE higher.

Fourth, the Department reviewed its own recent ROE awards and found the following: The Connecticut Light and Power Company, 9.85% ROE in 2003, Southern Connecticut Gas Company, currently proposed for settlement at 10.0% as brought out at a October 20, 2005 Hearing, Yankee Gas Service Company 9.9% ROE in 2004, Aquarion Water Company, 9.75% ROE in 2005, and Crystal Water, 9.9% ROE in 2005. These recent awarded ROEs are all lower than the Company's currently allowed ROE of 10.45%.

Fifth, there has been a substantial reduction to the income tax rate paid by investors in common stocks. A new tax law was passed in late May 2003, that lowers the federal income tax rate on dividends to 15%, and the tax on long-term capital gains has been reduced from 20% to 15%. Both of these changes have caused common stock investments to become relatively more attractive to investors than they were since the time of UI's last rate case in 2002. OCC argues that it may not be possible to precisely determine the cost of equity impact, but it is reasonable to assume that the new tax law would lower the cost of equity. Conversely, Mr. Avera believes the market is efficient and stock prices should reflect all available information and investor expectations regarding the tax law changes. The Department generally agrees with the OCC, but recognizes there is considerable debate regarding this change in taxation of dividends and the impact it would have on the cost of equity analyses making it difficult to precisely estimate the impact on the cost of equity. Therefore the Department did not make a specific adjustment; however, it provides further justification that a lower ROE is warranted.

6. Conclusion on Cost of Equity

***96** In determining the cost of equity, the Department considered all of the witnesses' cost of equity analyses. The Department finds that UI is a company that now has less risk, both financially and operationally. Consequently, in regulating UI to allow a return commensurate with its needs, the Department has determined that its investors now require less of the Company in financial return than in 2002, when the return was established at 10.45%. Therefore, in consideration of the argument of the OCC, the Department believes that a reasonable range is 8.4% to 10.57%. As discussed above, the Department places greater emphasis upon the DCF analyses, which resulted in a range of 8.4% to 9.64%, and less upon risk premium results. The Department notes that the DCF analysis for UIL individually implied a cost of equity range of 4.3% to 6.8%. Therefore, the Department determines that 9.65% is a reasonable cost of equity for UI. Adding to this a reasonable return for flotation costs, the Department allows the Company a final cost of equity of 9.75%, and adopts such return in this proceeding. Accordingly, 9.75% shall also be UI's allowed return on equity (ROE) on the equity portion of its rate base.

While UI has claimed that a rate increase is necessary to improve the Company's financial condition due to downgrading of its credit rating, the majority of its financial problems are the direct result of the poor financial performance of the Company's parent company, UIL. Response to Interrogatory EL-104, Attachment 1. This is due to the fact that UIL's unregulated subsidiaries continue to operate at a loss. The record shows that UIL will continue to sell off its investments in several unregulated subsidiaries. The financial burden placed on UI to be the cash cow, to support the drain placed on UIL by the unprofitable, unregulated subsidiaries, should improve in the next year or two. As a result, UI and UIL's financial condition should drastically improve regardless of the outcome of this proceeding. OCC Brief, pp. 5 and 6.

The Department notes that legislation allows UI to earn additional revenues that are not considered for ratemaking purposes or the Company's earning sharing but increase overall returns to its shareholders. The Company is allowed up to a 5% (after tax) for a conservation and load management performance incentive. Also, UI is allowed a procurement fee and potential incentive for the procurement of transitional standard offer generation. The procurement fee is equal to 0.5 mills per kWh plus an incentive of up to 0.25 mills per kWh. In addition, recent legislation was enacted which allows UI $25/kW for load response and conservation and a $200 per kW incentive for Distributive Generation to encourage the reduction of Federally Mandated Congestion Charges.

In general, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses, due to the essential nature of their services as well as their regulated status. Even though the Company expressed that UI's beta has increased since the last rate case, the fact is that the investment risk of public utilities is relatively low. As such, the cost of equity for the electric industry is among the lowest of all industries in the U.S. In particular, public utility bond yields over the past two years have declined from the 7% range to the 4.5% to 5% range. These indicators, coupled with the overall decrease in interest rates, justify a decline in the overall equity cost rate.

7. Weighted Cost of Capital

***97** After study and deliberation of all cost of capital issues presented in this proceeding, the Department finds that 6.88% for 2006, 6.89% for 2007, 7.09% for 2008, and 7.48% for 2009 are fair rates of return. The approved capital structure and capital costs on the rate-making basis is as follows:

2006 Allowed Weighted Cost of Capital

		Embedded	Weighted
Capital	Ratio	Cost	Cost
Long-Term Debt	52.0%	4.24%	2.20%
Common Equity	48.0%	9.75%	4.68%
Total	100.00%		6.88%

2007 Allowed Weighted Cost of Capital

		Embedded	Weighted
Capital	Ratio	Cost	Cost
Long-Term Debt	52.0%	4.25%	2.21%
Common Equity	48.0%	9.75%	4.68%
Total	100.00%		6.89%

2008 Allowed Weighted Cost of Capital

		Embedded	Weighted
Capital	Ratio	Cost	Cost
Long-Term Debt	52.0%	4.64%	2.41%
Common Equity	48.0%	9.75%	4.68%
	——		——
Total	100.00%		7.09%

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2009 Allowed Weighted Cost of Capital

		Embedded	Weighted
Capital	Ratio	Cost	Cost
Long-Term Debt	52.0%	5.38%	2.80%
Common Equity	48.0%	9.75%	4.68%
	——		——
Total	100.00%		7.48%

***98** The Department finds that these rates, when applied to the rate base found reasonable for the Company, should produce operating income sufficient for UI to operate successfully and serve its ratepayers, maintain its financial integrity, and compensate investors for risks assumed.

I. SALES AND REVENUES

1. Sales Forecast

UI states that it has included in this filing its retail sales forecast for the 2006 to 2009 plan period. UI used sales data from the last ten years to determine a growth rate over that period and then used average historical growth to project sales. UI believes that this methodology is consistent with that used by the Department in the past to develop its analyses of UI's sales forecasts. For comparative purposes, UI also prepared a sales forecast utilizing a top-down methodology based upon the prior year's data, adjusted for estimated C&LM program savings, known large customer changes within the service territory and forecasted economic growth. Nichols PFT, p. 31; Schedule F-6.0, 6.1 and 6.2.

UI goes on to state that its historical performance over the last ten years shows a growth rate of approximately 1%, whether looking at the last two five-year periods or the overall ten-year period. Using this methodology, UI's forecast reflects a compound growth rate of .92% for the 2006-2009 period. UI notes that its top-down analysis resulted in a slightly lower growth rate of .9%. UI believes that these comparisons compare favorably with historical growth trends and provide a 'sanity check' regarding the reasonableness of the overall forecast. *Id.*

UI goes on to state that in the past, the Department has not ordered a specific methodology to forecast sales and that the Department has recognized that there are a number of methods that can be use to determine this data. In addition, the Department has recognized that the results of any forecasting model will vary based on the inputs that are applied to it, such as weather-normalization input values or assumed economic growth rates.

The Department has reviewed UI's forecasting methodology and forecasting results and finds them to be reasonable for purposes of setting rates.

2. Pole Attachment Revenues

In Docket No. 05-06-01, *Petition of The United Illuminating Company for a Declaratory Ruling Regarding the Availability of Cable Tariff Rate for Pole Attachments by Cable Systems Providing Telecommunication Service and Internet Access* UI requested the Department to issue a ruling that UI as a public service company, is authorized to offer a rate under Conn. Gen. Stat. § 16-332 only to persons or corporations operating community antenna television systems making television, and audio signals available for reception by customers of such persons or corporations and that cable systems that are providing Internet access and other services are not entitled to the cable Tariff rate. UI states that a favorable ruling would have allowed it to negotiate increased charges with those companies that attach to its poles. The increased charge would have provided additional revenues that UI would have applied to lower its overall electric distribution revenue requirement.

***99** In its application, UI had assumed that the Department would approve its request under Docket No. 05-06-01. As a result, UI forecasted an increase to its pole attachment revenues, *i.e.*, Other Revenues, in each year of the plan. Tr. 10/17/05, pp. 1419-1431 and Tr. 11/9/05, pp. 2332-2335.

In the Decision dated December 14, 2005, in Docket No. 05-06-01, the Department denied UI's request. This required UI to continue to bill the current rate for pole attachments, effectively reducing the Company's *pro forma* Other Revenues. UI adjusted its revenues to account for this change. Late Filed Exhibit No. 1;

The Department has reviewed UI's proposed revenue adjustment as it related to pole attachments and finds it to be reasonable.

J. COST OF SERVICE STUDY

1. Company Proposal

101-114] A cost of service study (COSS) is a detailed analysis of the cost to provide service to each rate class. The cost of service study results provide the overall system-wide rate of return on investment as well as the individual rate class returns on investment. These results act as a guide to the Company and the Department in designing rates and determining the appropriate rate increase to each rate class.

UI has not filed a COSS since 1992. This is the first time that UI is filing a cost of service study since electric restructuring began in 1998. UI no longer owns generation and rates have been unbundled into nine pricing components.

In the cost of service study, UI analyzed and arrived at rates of return for those functional components of UI's rates which are assigned rate base, revenues and expenses. These functions include the CTA, transmission charge (T), and the distribution charge (D).

UI used the minimum intercept method to allocate distribution costs to rate classes. This method determines the amount of costs that should be assigned to rate classes based on customer and demand allocations. To allocate those costs classified as being demand related, the Company primarily used class non-coincident peak demand allocators, and for the demand portion of secondary lines UI used the sigma non-coincident peak demand as an allocator. To allocate those costs classified as being customer related, UI used allocators based on the number of customers in each rate class and sometimes a weight was assigned to the number of customers. Lundrigan, PFT p. 14. UI allocated costs to the CTA based on demand and energy. UI allocated transmission costs to rate classes based on the 12 monthly non-coincident peaks.

As JDL Exhibit 1 shows, there are large differences in the overall rate of return between rate classes. The current overall rates of return vary significantly, from a positive 38.6% for Street Lighting Municipal Company-Owned Rate M to a negative 12.7% for Qualifying Facilities, Rate NUS.

Rates of return also vary significantly between rate classes for the CTA, transmission and distribution functions. UI explains that this occurred because when UI's rates were initially unbundled on January 1, 2000, the CTA charge formed a ‘residual‘ rate component after all other amounts were subtracted from the ‘starting point‘ price level established in Docket 99-03-35 (*i.e.*, the price in [per kWh that each rate class paid in 1996, less 10%). In short, all of the other known factors (*i.e.*, the standard offer generation charge, SBC, C&LM, REI, T and D) were subtracted, from the starting price and the CTA residual insured that each rate schedule received the required 10% discount. The result was that each rate schedule paid a different CTA charge.

***100** Based on the results of the COSS, UI is seeking increases to the distribution and CTA components of customers' rates. UI proposed that all of the $2.5 million proposed increase to the CTA be allocated to residential customers. In addition, UI proposed higher rate increases to residential customers to move all of its D rate schedules closer to a ‘unity‘ cost of service D rate design by 2009. UI states that its prices to industrial customers are higher in relation to national prices than either the prices to commercial or residential customer. Lundrigan PFT, p. 9. UI did not propose any increase to the transmission charge in this proceeding.

CIEC and CBIA support the Company's proposed cost study and agree with UI's proposals to increase residential rates more than the overall average and provide lower rate increases to commercial and industrial customers.

2. Position of the OCC

The OCC presented prefiled testimony prepared by an expert witness on cost of service issues. The OCC believes that there are flaws in UI methodology and when these problems are corrected the results do not support the conclusions reached by UI which is to allocate larger proportion of the rate increase to residential customers. The conclusions and recommendations expressed by the OCC are generally supported by the AG.

The OCC testified that UI has allocated too many distribution system costs to residential customer on the basis of the number of customers. These problems result from an allocation methodology called the ‘minimum distribution system‘, that allocates some of the cost of poles, wires, the underground distribution system, and transformers (accounts 364-368) on the basis of the number of customers in each class, rather than on the loads imposed on the system by customer classes. UI's primary justification for utilizing this method seems to be that it is described in a pamphlet called the NARUC 1992 Cost Allocation Manual.

The OCC testified that the UI's distribution costs are not caused by the number of customers on the system. The OCC recommends that the Department not use the minimum intercept method.

The OCC further testified that even if the Department supported the ‘minimum distribution system‘ concept of identifying an amount of plant necessary to provide for minimum load, the Company's computation of that amount of plant was overstated. The formulaic approach used by UI is inconsistent with the initial goal of the methodology, which is to estimate the minimum cost of a system built to provide access to customers but to serve zero or minimal load. The result of using the UI methodology to calculate the customer related costs of the underground system is that a portion of underground system costs are allocated on the basis of the number of customers, when the excess (over above-ground) costs of installing underground were not necessitated by the number of customers on the overhead system.

According to the OCC, another problem in the Company's cost allocation study is that for the portion of secondary lines that was considered demand related, it utilized the sum of individual customer peaks as the allocator. This assumes that there is no diversity of load on secondary lines, and is inconsistent with the allocation of transformers, which are allocated on the basis of class non-coincident peaks.

***101** The OCC reallocated distribution costs, using the Company's model, both entirely on the basis of demand and also with a corrected minimum distribution system. These cost of service revisions resulted in lower residential distribution costs and lower customer costs.

The sum of these revisions to the Company's cost of service study, in which both the allocation of the CTA and of distribution plant in Accounts 364-368 were modified, shows that the residential distribution rate of return (average of all residential classes) is slightly below the system average rate of return, the GS-ND class as a whole produces a negative rate of return, the GS Demand class produces a rate of return that is considerably higher than the average, the GS time-of use and heating rates produce lower rates of return than the residential class, and the LP industrial class produces a return that is just barely positive.

Testimony by the OCC criticized this proposal as not consistent with Connecticut regulatory practice and as not recognizing the higher CTA contributions made by the residential classes in the past.

The OCC testified that the residential class Rate of Return (ROR) on the CTA was not as low as UI's cost of service study indicated. The Company's allocation of CTA expenses was erroneous, as it did not reflect the basis on which those costs were incurred. CTA costs that resulted from nuclear stranded costs were allocated on the basis of peak loads. The OCC testified that the rationale for spending more for nuclear capacity than for peaking capacity was to save energy. Even though a portion of nuclear investment might have been made to meet peak load, the OCC testified that this portion of nuclear costs was paid by purchasers of the assets, so that remaining stranded costs were entirely energy related. Tr. 10/06/05, p. 1637. Principles of cost causation therefore clearly indicate that CTA costs should be allocated on the basis of energy alone. CBIA and CIEC support the Company's cost of service study and the lower rate increases proposed for Commercial and Industrial customers.

The OCC recommends that CTA increases should be applied equally to all customer classes. The OCC also recommends that the residential class should not receive more than the system average distribution rate increase, as the OCC supported cost of service study showed that the residential distribution ROR was only slightly below the system average.

3. Department Analysis

This is the first COSS prepared by UI since 1992. Since that time, the electric industry has been restructured and rates have been unbundled. Over the years rates have changed several times, but for policy reasons, were generally adjusted on an across the board basis to provide equal percentage increase or decrease to each rate class. The Department recognized that it was time to reexamine the cost basis for UI rates and ordered the Company to provide a COSS at the time of its next rate case. UI has provided a cost study in this proceeding in compliance to that order. In the cost study, UI has examined the cost to provide service for three components of its rates; distribution, transmission, and CTA.

***102** UI's analysis clearly indicate that residential customers are providing a lower rate of return than other rates classes for the rate components examined. UI's analysis is used to support their proposal to increase residential rates by more than the average to bring the rates of return closer to unity.

The Department has reviewed the cost study and the comments of interested parties. The Department concludes that UI has followed commonly practiced methodologies that are generally consistent with prior rulings by the Department. The Department discusses UI methodology in more detail below and will order some modifications.

a. Distribution

The Company has used the minimum intercept method to allocate distribution cost to rate classes in its cost study. Under this method fixed costs are allocated on the basis of customers and demand. The OCC criticizes this method and recommends that no costs be allocated based on number of customers. The allocation of fixed distribution costs using the minimum intercept method is widely accepted and a common practice throughout the electric industry. The Department has approved its use in the past and finds no compelling reason to change at this time. The Department therefore will examine UI's allocations in their study as to their consistency with the minimum system method.

b. Accounts 366 and 367 Underground conduit and conductors

The OCC does not believe that UI properly applied the minimum system method to its underground facilities. According to the OCC the result of using the UI methodology to calculate the customer related costs of the underground system is that a portion of underground system costs are allocated on the basis of the number of customers, when the excess (over above-ground) costs of installing underground were not necessitated by the number of customers on the overhead system.

The Department recognizes that UI has substantial underground facilities due to its urban service territory. The factors that influence the decision to go underground and the higher associated costs are not related to the number of customers or demand. However, while underground facilities are not installed primarily because of demand, many customers on underground facilities are either commercial or industrial customers in urban areas. Thus, while demand may not be directly responsible for underground facilities, using demand as the allocator for excess (over above-ground costs) would more accurately align the costs of these facilities and the benefits derived to the customers that use them.

The Department, therefore, does believe it is appropriate to allocate the additional costs associated with underground facilities to rate classes on the basis of non coincident peak demands as the OCC recommends and will order the Company to do so at the time of its next COSS filing.

c. Account 368, Transformers

The Company used regression analyses of the cost of transformers, for each type of transformer, to estimate the cost of minimum size transformer by type. The estimates were then vintaged and multiplied by the number of transformers of each type on the system.

***103** The OCC disagrees with UI's proposal. This approach ignores the fact that transformers usually serve multiple customers, and the number of customers that transformers can serve depends on the load of those customers. As a result, if customers were smaller (as in, had minimum loads), many fewer transformers would be needed to serve the same number of customers. In addition, the minimum system will be less expensive if there are slightly larger transformers which serve more customers each.

The OCC estimated the number of customers (with a 0.5 kW load) that could be served by a 25 KVA transformer, and multiplied that by the vintaged average cost of the 25 KVA transformer to develop the minimum cost based on demand as proposed by the OCC.

The Department agrees with the OCC's basic concern; however its proposed premise for the minimum system line transformer capabilities overstates the number of customers assigned per transformer. Using OCC's minimum system load of 0.5 kW and 25 kVA line transformers results in a customer assignment of approximately 40 customers per transformer, assuming an 80% power factor. Given that non-heating customers are typically served by, at most, 10 customers per transformer, this is unrealistic even for the minimum system. Any theoretical approach to this issue would result in a minimum system that is grossly misaligned with the design characteristics of a real distribution system. The Department believes that the COSS should reflect a customer assignment to line transformers based on the actual typical minimal such assignment found in the distribution system, and will require the Company to change its studies below.

d. Secondary Lines

The Company allocates secondary line plant on the basis of what it has labeled 'SIGNCP'. This is the sum of the maximum customer demands of each class, whenever they may occur. The OCC does not agree with this allocation. This would imply that the system needs to be sized to meet the sum of all the individual peak loads on the lines and that there is no diversity in the secondary system. In actuality, the system parts will be sized to meet the maximum coincident load on the various parts of the system. The OCC recommends the class non-coincident peaks at the secondary voltage level, or what the Company labels allocator D06, better reflects cost causation.

The Department agrees with the OCC and will require the Company to use class non-coincident peak demand as the allocator for secondary lines.

e. Poles and Fixtures

The Company defined the minimum pole cost as the average cost of a 25 foot pole. This is the least expensive pole. It further treated 52.59% of poles as primary and 47.41% poles as secondary.

The Company estimated the split based on the relative circuit lengths of the overhead primary and secondary systems. Based on feet of conductor (wire), the total overhead system circuit length is 52.59% primary. The Company uses the primary length percentage to assign a portion of the cost of the poles to primary customers. This does not imply that 52% of the system poles carry primary wire and 48% carry secondary wire. This split between primary and secondary is splitting the cost responsibility for the poles between the primary and the secondary system.

***104** The OCC does not agree with the Company's proposal. The Company's method would be correct if a pole carried only primary system conductor or secondary system conductor. However, in the normal configuration, the same poles will carry both primary and secondary wire. The result of the Company's allocation is that the primary customers are being assigned too little of the cost of the poles and the secondary customers are being assigned too much of the cost. Almost half of the cost of the poles is being assigned only to secondary customers. Secondary customers are then assigned a portion of the primary system as well, which contains the cost of the poles assigned to the primary system. Primary customers are paying for only half of the poles, but all of the poles are needed to support the primary system. The OCC presents an alternate treatment for poles which allocates all costs based on primary customers.

The Department believes that the Company has properly allocated the cost of poles. The poles provide a duel function of carrying both primary and secondary lines and therefore it is appropriate to share the costs of poles and allocate the costs to rate classes as proposed.

f. Other Costs

UI has allocated a number of accounts based on weighted customers. The Department has reviewed those allocations and finds that generally to be reasonable in theory however, the data and cost relationships used to develop the weighting are often old and were not updated for this study. The cost categories affected are generally small and the overall impact is also relatively small and therefore the Department will not require any changes at this time. The Department will order the Company to review and update its weighted customer allocations at this time of its next COSS.

g. CTA

UI allocated CTA costs that resulted from stranded nuclear costs on the basis of peak demand. OCC recommends that all CTA cost should be allocated on the basis of energy use. During the proceeding UI agreed that a portion of these costs should be allocated on the basis of energy. However, UI continued to support allocating 8% (the proportion of hours in the Company's load research definition of peak hours) of these CTA costs on the basis of class coincident peak demand.

The Department agrees with the OCC that nuclear plant was primarily built to provide low energy prices and, therefore, should be primarily allocated on the basis of energy; however, it is appropriate to allocate a portion of base load plants on the basis of demand. The allocation of a portion of nuclear stranded costs on the basis of energy and demand is consistent with the Department's prior treatment of base load generation costs and accepted cost allocation methods in the industry.

The Department will order UI to allocate stranded nuclear costs associated with peak hours on the basis of coincident peak demand as agreed by UI. The remaining costs associated with the shoulder and off peak periods shall be allocated to rate classes based on energy.

***105** However, since the Department is not approving any increase to the CTA, see discussion below, there will be no change to the CTA rates at this time.

h. Transmission

The Company allocated transmission costs on the basis of 12 monthly coincident peak demands. Lundrigan PFT, p. 17. No parties disagreed with this allocation. The Department agrees that peak demands are the primary factor used when sizing transmission facilities and the allocation of costs between Companies by ISO-NE for the Regional Network System. The Department will therefore accept UI's proposal. While no increase has been proposed or granted for transmission in this preceding this ruling effects the overall calculation of the rate of return for each rate class. In addition, the Company should use this method as a guide to allocate future transmission rate increases.

i. Conclusion

The Department has reviewed the cost study and the comments of interested parties and orders some modifications as discussed above. These changes generally reduce the disparity between the rate of return for residential rates and other rate classes but still indicates below average returns for the rate components examined.

The principal weakness of the cost study is that UI did not examine all of the rate components. UI did not examine the SBC, GSC or By-passable and Non by-passable FMCC charges. The exclusion of these rate components, particularly the GSC reduces the Department confidence in UI's conclusion and willingness to fully accept UI's proposal regarding the level of rate increase to each rate class at this time. The exclusion of some rate components has also made it nearly impossible to examine the cost basis for its seasonal and time-of-use rates. .

The Department will allow UI to increase residential Rate R rates by 3.0% in 2006 and Rate RT by the average of 1.98%. Rates to most commercial industrial customers and Street Lighting customers will be increased by less than the average increase approved. Rate GST and LPT shall be increased by 1.0% and Rate M and Rate U by .75%. The Department will approve rate increases to other rate classes as proposed but adjusted to reflect the allowed average rate increase. The Department will not determine the rate increases for 2007, 2008 or 2009 at this time. The Department will require UI to conduct a full cost study including all of its rate components by October 1, 2006. UI shall bid out the generation sources by customer or rate class for 2007. If this cannot be done, the Company should estimate the cost of generation by rate class by using available information. The Company shall use the allocations approved in this proceeding for the Distribution, Transmission and CTA rate components. The Department will not relitigate these allocations at that time. Our intent is to determine appropriate allocators for the remaining rate components and examine the results in total. The study should also include the analysis of costs by time periods to assist in the development of time-of-use and seasonal rates for each component of its rates.

K. RATES AND RATE DESIGN

1. Interruptible Tariff

***106** UI proposes to eliminate its interruptible tariff, Load Control Rider LC. Lundrigan PFT, p. 14; Tr. 10/6/05, p. 226.

At this time the Department denies UI's request. However, the Department intends to address this issue in a supplemental Decision to be issued in this proceeding.

2. Combining Rates A and RT

UI proposes to combine its two residential time-of-use (TOU) rates, Rate A and RT, in order to simplify its tariffs and to provide expanded off-peak hours to customers being served under Rate A. Under its proposal, Rate A would be eliminated and all customers served under that tariff would be served under Rate RT. Lundrigan PFT, p. 11; Tr. 10/6/05, pp. 325-328; Response to Interrogatory EL-294.

UI states that based on its proposal, customers taking service under Rate RT will experience an increase that is greater than the Company-wide average while the current Rate A customers would experience an increase that is less than the Company-wide average increase. UI indicates that this will occur because there are seven times as many Rate A customers than there are Rate RT customers and because the average rates under Rate A are 1.0 cents per kWh higher than those assessed under Rate RT. *Id.*

The load characteristics of customers served under Rates RT and A are similar. In addition, the Rate A off-peak hours are 11 p.m. to 7 a.m., while the Rate RT off-peak hours are 8 p.m. 9 a.m. Therefore, it is reasonable to combine these rates. Further, moving Rate A customers to the tariff for Rate RT will expand the off-peak hours available for Rate A customers, affording them an opportunity to further reduce their electric rates. Based on the foregoing, the Department finds UI's proposal to be reasonable.

3. Reprogramming TOU Meters and Load Control Devices

UI states that it serves about 30,000 customers under its TOU rates and that the requirement to extend daylight savings time will require the Company to reprogram these meters. UI goes on to state that it will be able to reprogram the vast majority of these meters through its master metering system at a cost of approximately $156,000. In addition, the Company has load research meters and approximately 24,000 Rate A load control devices for water heaters which would need to be manually reprogrammed at a cost of up to $1.9 million. The Company did not include a request for the $1.9 million in its application because it believes that the Department will approve its request to eliminate Rate A by combining Rates A and RT. Tr. 10/6/05, pp. 231-238.

To avoid the $1.9 million cost, UI proposes to leave the setting for its load control devices at the current hours, switching these devices 'on' at 11 p.m. and 'off' at 7 a.m., while moving these customers to Rate RT. However, the on and off peak times are different for Rates RT and A. Therefore, these devices, which are used to control the heating elements for storage water heaters, would not be synchronized with the on/off peak hours under Rate RT.

***107** UI believes that most customers would be indifferent to the mismatch of the times for the water heater load control devices because customers who are currently served under Rate A are able to satisfy their domestic water heating needs based on the current on/off peak time parameters of Rate A. Further, UI notes that if the federal government were to revert back to the current standard for daylight savings, then utilities that incurred reprogramming costs would need to expend additional resources to return these meters and load control devices to their original time settings. *Id.*

The Department believes that it is reasonable to allow UI to leave the settings for its load control devices at the current hours in order to avoid the significant expense of reprogramming them at this time. However, UI must adjust the settings for any customer who wishes to have their load control device reflect the on/off peak hours under Rate RT and when a site visit to load control customers is warranted. This would include a visit to service a rental water heater. Regarding the need to incur $156,000 in reprogramming costs, the Department finds this request to be reasonable and notes that UI has accounted for this cost in its revised filing under Late Filed Exhibit No. 1. The Department accepts this adjustment.

4. Combined Public Benefits Charge

The Company intends to combine the Conservation and Load Management Charge, Renewable Energy Charge and Systems Benefit Charge on customer bills and will implement this change in the first quarter of 2006. However, UI would prefer to continue to show these charges separately on its tariffs. Tr. 10/6/05, pp. 235-237.

UI's proposal to combine these three charges on customer bills is consistent with current Department regulations. Therefore, the proposal is approved. The combined charge will be titled Combined Systems Benefits Charge on customer bills and shall be explained in a footnote that must remain on the bill. In addition, the Department requires UI to show these items as a Combined Public Benefits Charge on its tariffs with an explanation of the individual charges that comprise this charge.

5. Summary of Rates

The Department believes that customers would benefit if UI's tariffs included a summary of the Company's total generation, transmission and distribution charges. Therefore, the Department requires UI to include a section within each tariff that summarizes these charges. This is intended to facilitate the customers' understanding of their electric rates.

6. Monthly Customer Charge

UI proposes to apply larger increases to fixed distribution charges such as the monthly customer charge rates and demand-based distribution rates. UI states that this type of rate design is appropriate because all distribution costs are fixed. Lundrigan PFT, 8.

For residential customers, the Department requires UI to apply the increase to the monthly customer charge during the plan period. Regarding demand-based rates, UI's proposal to apply the increase to customer and demand charges is reasonable.

***108** The Department examined alternative designs for UI's monthly customer charge. Tr. 10/6/05, pp. 240-269; 320-335. The Department will issue a supplemental Decision to address this rate design issue.

7. Demand Rates for Residential Customers

The Department examined the potential to establish demand-based billing for residential customers, including ratcheted demand charges. Tr. 10/6/05, pp. 269-279.

The Department will issue a supplemental Decision to address this rate design issue.

8. Mandatory Time-of-Use Residential Rates

UI proposed certain policies regarding the assignment of customers to time-of-use and demand-based rates. In addition, the Department examined the potential to establish mandatory time-of-use rates for all residential customers. Lundrigan PFT, p. 7; Tr. 10/6/05, pp. 284-311.

The Department will issue a supplemental Decision to address this rate design issue.

9. Demand Ratchets

At present, UI's Large Power Time-of-Use Rate, Rate LPT, is the only tariff that includes a demand ratchet. [15] Rate LPT bills for demand based on the 'greatest demand registered during the On-Peak hours of the month, but not less than 80% of the On-Peak Demand in the preceding months of June through September.' This rate design is intended to provide an incentive for customers to control summer peak demands.

The Department explored the potential to expand the application of mandatory ratcheted demand charges to UI's other commercial and industrial rates. Response to Interrogatory Nos. EL-394 and 395. Tr. 10/6/05, pp. 305-310; 347-352; 394-404.

The Department will issue a supplemental Decision to address this rate design issue.

10. General Service Heating Rate, Rate TE

UI proposes to eliminate its General Service Heating Rate, Rate TE, and to transfer these customers to either the General Service Rate GS or General Service Time-of-Use Rate GST. UI states that there are approximately 100 customers that take service under Rate TE and that the rate is closed to new customers. In addition, UI notes that by transferring to Rate GS, Rate TE customers will receive a lower than average rate increase. Lundrigan PFT, p. 14; Schedules E-2.0A and E-2.1A.

The Department has reviewed UI's proposal to eliminate Rate TE and finds it to be reasonable. UI must transfer these customers to the rate that is most beneficial.

11. Terms and Conditions

UI has proposed several changes to its current Terms and Conditions including adjustments to several supplier-related charges as well as a number of ancillary customer service related charges such as load survey and meter reading fees. Lundrigan PFT, p. 15; Schedule E-1.0A; Response to Interrogatory EL-278.

***109** The Department will issue a supplemental Decision to address UI's Terms and Conditions and the charges that are detailed in the response to Interrogatory EL-278. Therefore, UI must maintain these charges at their current level.

12. Rate NUS

UI proposes to modify the wording of its Non-Utility Generating Facility Standby Rate, Rate NUS, to make it clear that any customer with a self-generation facility with a nameplate rating of less than 100 kW is not required to take Rate NUS for its backup requirements, whereas, any customer with a self-generation facility of 100 kW or greater must receive its backup service requirements under Rate NUS. Therefore, UI is proposing to make Rate NUS mandatory for any customer with a self-generation facility of 100 kW or greater. Lundrigan PFT, p. 14; Response to Interrogatory EL-247.

UI indicates that if generators with ratings of 100 kW or greater, which were installed prior to January 1, 2006, are not required to take service under Rate NUS for backup service that the Company could face a revenue shortfall of approximately $2.5 million. UI goes on to state that these revenues would need to be allocated to all other customers and recovered through their rates. *Id.*

Pursuant to the Decision dated April 16, 2003, in Docket No. 02-02-06, *Request of Housing Ministries of New England Inc. for Review of UI's Rate NUS at the Washington Heights Apartments in Bridgeport, CT*, the Department ruled that UI could not require a customer to take backup service under Rate NUS. Therefore, UI's request to modify the tariff is denied.

The issue surrounding backup rates centers on the investment that UI must make in distribution plant assets that are necessary to stand ready to serve customer load. UI is concerned that unless it can assess backup or standby charges to customers that operate self-generation equipment that it will not recover the revenue necessary to support the plant investment that are required to stand ready to serve these customers. However, UI states that its concerns would be lessened if commercial and industrial rates included mandatory demand ratchets.

As noted above, the Department intends to address the issue of demand ratchets in a supplemental Decision in the instant proceeding. The Department intends to consider implementing demand ratchets for commercial and industrial rates that currently do not use demand ratchets and to expand distribution ratchets to be effective year-round.

13. Economic Development Rates

UI proposes to eliminate its Economic Development rider. The Department has reviewed UI's proposal and finds it to be reasonable.

14. Load Control Equipment

UI proposes to implement some additional load control charges under its residential TOU rates. The Department intends to address this matter in a supplemental decision in this proceeding. Therefore, UI cannot proceed with its plan to implement these strategies at this time.

15. Net Metering

***110** At the Department's request, UI proposed to modify its Net Energy Rider NE. The Department will address this rate design issue in a supplemental decision to be issued in this proceeding.

16. Pole Attachment Tariff

At present, UI does not have a Pole Attachment tariff (CATV Tariff). Instead, it is assessing the pole attachment charge that had been approved for the Southern New England Telephone Company (SNET). [16]

UI states that it is the 100% owner of 3,433 poles and the 50% owner of 115,423 poles upon which cable companies attach their facilities. Based on the current pole attachment charge, UI receives $356,472 in annual attachment revenues, or approximately $5.83 per attachment. UI believes that its current charge does not recover the cost associated with providing this service. As a result, UI developed a revised charge using the assumptions specified in Docket No. 92-09-19 including the use of the Federal Communications Commission (FCC) cable formula and an adjustment to the net pole investment with a ratio of 90% embedded cost and 10% marginal cost. UI also states that it has endeavored to follow the assumptions on how the components of the existing tariff charge was developed and has used its most current annual cost information for the period ending December 31, 2004. Based on that methodology, UI states that its pole attachment charge should be $12.21 per attachment, resulting in annual revenues of $746,574. In response to the Department's request, UI developed a CATV Tariff. Late Filed Exhibit No. 61.

UI notes that because it did not include a request to increase its CATV Tariff charge as part of the instant application, that it has not notified those customers that would be affected by an increase in this charge. Accordingly, UI suggests that the Department's decision in the instant docket approve the language contained in the proposed CATV Tariff and that the existing rate of $5.83 per attachment continue to be assessed. UI requests that the Department then schedule a hearing to address a new CATV Tariff rate as a Phase 2 component of this docket. *Id.*

The Department has reviewed the language of the proposed CATV Tariff and finds it to be reasonable. Regarding the rate, because UI did not propose an adjustment to the CATV rate it must continue to assess the current charge, which must be reflected in the tariff. If UI believes that its CATV Tariff charge should be adjusted, it must request an increase to this rate. UI will be required to submit a final CATV Tariff.

17. Rate R — Seasonal Rate Provision

***111** UI proposes to eliminate the seasonal cottage rate from the Residential Rate R tariff. The Company states that the seasonal provision for cottages became effective in the 1940's and was offered at a time when many customers occupied certain properties seasonally. UI goes on to state that most of these dwellings have been converted to year round dwellings and that there are fewer than 200 accounts utilizing this provision of the tariff. UI proposes to transfer these accounts to Rate R and states that there is no revenue or metering impacts associated with this change. Schedule E-1.0 A; Tr. 10/6/05, pp. 208-211.

The Department has reviewed UI's proposal and finds it to be reasonable.

18. Rate RHP — Heat Pump Rider

UI proposes to implement a Residential Heat Pump Rider (RHP). UI states that this rider will provide an energy efficient electric option for heating homes, and notes that the discount, $5/ton, is designed to offer an overall rate that is competitive with gas or oil alternatives.

Pursuant to the Decision dated January 17, 1996, in Docket No. 95-07-13, *Application of The United Illuminating Company for Expedited Approval of Residential Heat Pump Rate RHP*, the Department approved UI's request to implement a separate rate for customers that use an electric heat pump as their primary source of space heating. Pursuant to the Decision dated December 9, 1999, in Docket No. 99-03-35, *DPUC Determination of The United Illuminating Company's Standard Offer*, the Department eliminated UI's Heat Pump Rider effective December 31, 2003. Pursuant to the Decision dated July 21, 2004, in Docket No. 99-03-35RE10, *DPUC Determination of The United Illuminating Company's Standard Offer — Rate RHP*, the Department reinstated a heat pump discount for UI's customers. In that Decision, the Department determined that it was appropriate to eliminate the heat pump discount by phasing it out over time. The Department required UI to apply a declining discount to the rates being assessed to former Rate RHP customers and to eliminate the discount at the end of 2006, eliminating the rate at that time. This action was taken to comply with the Special Contract provision of Public Act 98-28.

The discount for heat pump customers will expire at the end of 2006. Based on the requirements of Public Act 98-28 and previous rulings, the Department denies UI's request to continue a residential heat pump discount.

19. Special Contracts

Pursuant to the 01-10-10 Decision, the Department required UI to reduce rates to flexible rate customers that would also be subject to general rate increases. 01-10-10 Decision, p. 89. The Department directs UI to apply the rate increase granted herein consistent with the ruling in Docket No. 01-10-10.

20. Water Heater Rental

***112** UI proposes to increase the current monthly charges under its Water Heater Rental (WHR) Rate from $7.00 to $7.70 for an 80/100 gallon heater and from $8.50 to $9.00 for a 120 gallon model. These charges would not change during the Rate Plan. In addition, the current tariff requires that a customer pay an installation charge of $350 for the 80, 100 or 120 gallon size heaters. UI believes that the installation charge is a barrier to customers utilizing Rate WHR and proposes to offer a second option under this rate to overcome this hurdle. UI proposes to allow the customer to forgo the installation charge and instead pay a higher monthly rental fee. Under this option, the monthly rental charges would be $12.50 for the 80/100 gallon heater and $14.00 for the 120 gallon model. These charges would not change during the Rate Plan. UI believes that by eliminating the installation charge it can add 500 controlled heaters per year to its existing fleet of storage heaters. UI would require that all new customers control their water heaters to limit the on-peak consumption of electricity. Schedule E-1.0.A; E-1.0.B; E-1.0.C; E-1.0.D; Tr. 10/6/ 05, pp. 419-423.

The Department has reviewed UI's proposal and believes that it is reasonable to increase the current rental fees under Rate WHR to the level proposed by UI. In addition, the Department believes that it is appropriate to offer customers the option to forgo the installation charge and to pay a higher monthly rental charge to eliminate any barrier to participating in this program. The Department has reviewed the proposed charges and finds them to be reasonable. UI must include language in its tariff to require customers to control this load. At this time, UI cannot assess a separate charge for the cost of the load control device.

The Department encouraged UI to promote its Rate WHR because, combined with the benefits of Rate RT, customers can reduce their electric costs by controlling their on-peak electric consumption. *See* Decision dated March 30, 2005, in Docket No. 04-11-01, *DPUC Review of CL&P and UI Conservation and Load Management Plan for Year 2005.* Decision, p 7-10. The Department continues to believe that this type of program provides value to UI, its customers and the electric system as a whole.

21. Surge Protection Service Tariff

UI proposes to maintain the current charges (Option A) under its Surge Protection Service Tariff at $62.00 for installation and the charge of $4.95 per month. However, UI proposes to offer a second option (Option B) to allow the customer to forgo the installation charge and instead pay a higher monthly charge. Under this option, the monthly rental charge would be $5.95. These charges would not change during the Rate Plan.

The Department has reviewed UI's proposal and finds it to be reasonable.

L. COMPETITIVE TRANSITION ASSESSMENT

Separate from the distribution rate increase, UI also proposed to increase the CTA rate to reflect the revenue requirements impact resulting from the proposed ROE and capital structure as well as the impact of the CCBT surcharge. The CTA revenue requirement increase is $2,564,000, $2,174,000, $2,531,000 and $2,979,000for the years 2006-2009, respectively. Schedule H-3.0 A-D, Total Company; Nicholas PFT, p. 3.

***113** In separate sections in this Decision, the Department makes adjustments to the proposed ROE, capital structure and UI's cost of debt. The Department also removed the CCBT surcharge for 2008 and 2009. The impacts of these adjustments must flow through to the CTA.

The CTA revenues and expenses are reviewed annually in a separate proceeding. The Department requires UI to incorporate the changes to the ROE, cost of debt, capital structure and CCBT rate into its CTA calculations beginning in 2006. As stated in the December 19, 2005 Decision in Docket No. 99-03-35RE11, *DPUC Review of The United Illuminating Company's Standard Offer — 2004 Reconciliation of CTA and SBC*, UI has a cumulative CTA underrecovery of $29.75 million. Therefore, the Department does not believe it would be appropriate to decrease the current CTA rate due to the adjustments made in this Decision. The Department believes the best course of action would be to allow UI to apply any overrecoveries in the

CTA earnings or income taxes to offset the cumulated CTA underrecoveries. Therefore the Department removes UI's entire CTA rate increase request of $2,562,000, $2,171,000, $2,525,000 and $2,974,000 for the years 2006-2009, respectively. *M. GENERATION SERVICES CHARGE*

128, 129] UI currently collects many costs that could be deemed generation services charge (GSC) related through the distribution rate. Many of these costs should be avoidable by customers who choose a third-party supplier, but are not because all customers pay the distribution rate. In addition, the true cost of supplying generation is not readily known because some GSC costs are embedded in the distribution rate. UI submitted in Late Filed Exhibit No. 27 a listing of the costs, description and an explanation of how the costs currently are collected and could be collected:

1) *The portion of the non-hardship uncollectible expense attributable to generation services charges.* For instance, if 50% of the average bill were comprised of generation services charges, then 50% of the non-hardship uncollectible expense could be allocated to the GSC component, for customers receiving their generation services through UI. As noted in the response to EL-390, the proper allocation of uncollectible expense is critical, since, for internal accounting purposes, non-bypassable federally mandated congestion charges are considered GSC expense, yet they are not 'bypassable' or billed to customers in the generation portion of their bills.

2) *The return on certain rate base assets shown in Schedule WP C-3.30.* The assets that are related to supplier relations or load settlement activities could be recovered through the GSC. These costs are not 'avoidable' by customers choosing a third-party electric supplier since the system costs do not go away.

3) *A portion of the revenue requirements associated with the working capital allowance.* The portion of the working capital expenses attributable to the wholesale power supply could be allocated to the GSC rate component. This item would vary as customers choose alternate suppliers.

***114** 4) *The payroll and associated IT infrastructure and support related to the employees performing supplier relations, power contract administration and ISO load settlement.* Per Department decision, these costs are already included in the GSC and are part of the semi-annual reconciliation process. These costs do not vary as customers choose alternate suppliers since the systems and job requirements do not change based on the number of customers served by alternate suppliers.

5) *The TSO procurement fee and possible incentive procurement fee.* These items are already in the GSC and included as part of the semi-annual reconciliation process.

6) *Legal Fees.* Legal fees incurred during the execution of GSC-related dockets are currently charged as a GSC expense, and are part of the semi-annual reconciliation process. These costs are not 'avoidable' by customers choosing a third-party electric supplier.

7) *Regulatory Commission Expense.* Currently, the regulatory commission expense is allocated 100% to distribution. To the extent that many regulatory activities are GSC-related, a portion of that expense could be allocated to GSC. The exact methodology for calculating that allocation would need to be determined and included as part of the semi-annual reconciliation process. These costs are not 'avoidable' by customers choosing a third-party electric supplier.

In addition, the return of (depreciation expense) assets used to support generation is currently recovered in the GSC. UI testified that the transmission tariff should be paid by the generators as a shipping cost. Currently, the only charge paid by third party suppliers is the supplier initialization fee. The fee is based on the costs to set the supplier up on UI's system. UI also testified that the next time its GSC rate is reviewed it would be appropriate to discuss other costs that should be collected in the GSC. Schedule C-3.30; Tr. 10/17/05, pp. 1355, 1356 and 1366; Tr. 11/9/05, p. 2407.

The Department believes other costs such as billing services and customer service functions can be identified as GSC related. The Department believes that the time is right to explore how costs related to the GSC are collected by the electric distribution companies. Should the costs continue to be collected in the distribution rate? Should the costs be collected in the GSC rate and to the extent they also provide service to third-party suppliers, should they be billed directly to the third-party suppliers? The Department believes that customers should receive the most accurate price signal regarding the cost of energy. Also, suppliers should know the actual cost incurred by the electric distribution companies for generation services so they know the price they have to compete with.

The Department intends to open a generic proceeding to determine which costs are avoidable if a customer chooses a third party supplier and which costs are not. In addition, the Department wishes to identify the types of costs that should be collected by all electric distribution companies through the GSC or billed directly to third-party suppliers. This proceeding will also quantify the costs involved so rates could be adjusted in each electric distribution company's next transitional standard offer docket.

N. CUSTOMER SERVICE ISSUES

***115** *1. Customer Information System/UI's Call Center*

a. Background

130-132] The Company's new Customer Information System (CIS) went on line the week of November 10, 2003. Before that date the Company, in anticipation that customers might experience longer hold times, prepared by sending out customer notices through its bill inserts (the Source). With the new technology the Company was also able to modify the Automatic Call Distributor (ACD) to put a message up front when customers called, advising them that they might experience a longer hold time and providing them with an estimated wait time. Tr. 10/18/05, pp.1508 and 1509.

According to the Company, it faced three challenges when implementing the new technology in its call center. The first was that the Company was going from a 25 year old main frame system to a state of the art Windows based system. The new system is equipped with more functions which added to the learning challenge the Company's employees faced. The second challenge was there were several market and regulatory changes that also had a direct impact on customer's rates and bills at this time. This prompted more calls to the Company and the representatives now had to balance customers' requests for information as well as trying to become proficient with the new CIS system. The third challenge was attrition which the Company claims limited its ability to do additional training to try and improve the representatives' efficiency. Response to Interrogatory CA-1.

b. Call Center Staffing

The Company witness testified that the average number of representatives answering the telephones in the call center and credit and collections is 40-45. There are eight bilingual representatives who take Spanish calls as a first priority, but will also take overflow calls if necessary. Tr. 10/18/05, pp. 1524-1529.

The AG states that all of UI's customer bill inserts should be in Spanish and that a Spanish speaking representative should be available in UI's customer service center at all times. AG Exceptions, 1/19/06, pp.13 and 14. The Department is in complete agreement with the AG's position in this regard. The information the Company provided in Late Filed Exhibit No. 90 shows that many of the bill inserts the Company has issued in the recent past were not in Spanish. The Department notes that there are two major cities, Bridgeport and New Haven, in UI's service territory. Both these municipalities have a significant number of customers who UI serves and whose primary language is Spanish. These customers rely on the bill inserts for a variety of topics including how to conserve energy and the like. Therefore, the Department will order the Company to put all future customer bill inserts in Spanish, as well as English.

c. Call Center Recruitment and Testing and Training

The Company recruits candidates for the call center through job fairs, the Connecticut Job Bank and the Company's monthly newsletter (the Source). The Company does not employ a recruitment firm to assist in the hiring for the call center. The Company testified that it traditionally uses its own Human Resource Department with an established testing procedure which has recently been changed. Tr. 11/09/05, pp. 2153-2155.

***116** In the past, the Company has had difficulty in hiring candidates for its call center because 86% of the candidates taking the test were failing. Therefore, in the second quarter of 2005 the Company began using a new testing method developed by the Edison Electric Institute (EEI) which was designed for call center operations in the utility industry. The initial results show that approximately 50% of candidates are now passing the test. The Company states that the test has given it a better bank of (test qualified) candidates not only for the call center but within other customer service and client fulfillment areas. In this way the Company can prepare for positions that might open in those areas so it can fill them quickly with a qualified person. Response to Interrogatory CA-2; Tr. 11/9/05, pp. 2157 and 2158.

The Company testified that its call center representatives were trained for approximately 40-60 hours before the new CIS system went live. However, the Company witness testified to the fact that it did not anticipate the loss of representatives due to attrition, medical leaves and turnover which contributed to the long hold times and abandoned calls. Tr. 10/25/05, pp.1512 and 1513; Tr. 11/9/05, pp.2166 and 2167. The Company did admit that the length of time it took to learn the new technology had come as a surprise and that the Company had basically underestimated the representatives' learning curve. Tr. 10/25/05, p. 1516.

The Department believes that the Company greatly underestimated the amount of time it would take for the call center representatives to learn the new CIS system. The Department questions why the Company would install a new CIS system without first having a substantial bank of qualified representatives ready to take on the task of learning an entirely new system. The Company witness admitted that another factor that contributed to a dip in customer service was that along with the CIS system a new ACD system and a new wireless technology system were installed in 2004. This meant that the employees had to learn the state of the art technology which also proved to be more difficult than anticipated. Tr. 10/18/05, pp.1503-1504.

d. Call Hold Times and Abandoned Call Rates

Monthly Average Customer Call Center Statistics,
January 2004 — November 2004

	1/04	2/04	3/04	4/04	5/04	6/04	7/04	8/04	9/04	10/04	11/04
# Calls											
Received	1999	2067	2109	2353	2755	2899	2937	2899	2647	2368	2221
# Calls											
Abandoned	418	428	412	391	504	728	817	661	212	209	158
% Calls											
Abandoned	19%	18%	17%	16%	17%	23%	25%	21%	8%	8%	8%
Hold Time	3:46	3:22	3:40	4:02	4:55	5:21	5:51	5:01	1:49	2:09	1:47
Avg. # CSR	42	43	43	43	45	40	34	36	45	41	42
Avg. Calls											

per CSR	47	48	49	55	61	71	83	81	60	57	53

Monthly Average Customer Call Center Statistics, December 2004 — September 2005

	12/04	1/05	2/05	3/05	4/05	5/05	6/05	7/05	8/05	9/05
# Calls Received	2174	2744	2201	2316	2677	2557	2675	2813	2718	2954
# Calls Abandoned	169	65	120	141	240	192	260	376	369	503
% Calls Abandoned	7%	3%	6%	8%	9%	7%	9%	13%	14%	16%
Hold Time	1:58	0:42	1:13	1:14	2:23	1:48	1:48	3:24	3:17	4:27
Avg. # CSR	43	47	44	48	44	47	46	39	41	42
Avg. Calls per CSR	50	56	50	49	61	53	58	68	65	69

***117** Source: Late Filed Exhibit No. 73

The Department began receiving complaints from customers within a few months of the new CIS system being installed. The customers complained that they were on hold for extended periods of time. It was at this point that the Department requested that UI begin filing weekly call center statistics.

The statistics that the Company filed for the months of April to August 2004 revealed that the average hold time on Monday's was 5.9 minutes and the average number of abandon calls was 838. The monthly average for call hold times from January 2004 — August 2004 was continually 3-5 minutes and the call abandoned rates went from 16%-25% as shown in the above chart. Late file Exhibit No. 73. The average number of representatives on Mondays was 46. Tr. 10/18/05, p 1493.

The Company testified that it tried to alleviate the long hold times and abandoned calls by offering overtime to the representatives and providing additional training to help them become more proficient. The Company also stated that it reevaluates representatives schedules quarterly based on call volumes and is now in the process of reevaluating because they have hired new representatives. Tr. 10/18/05, pp. 1529-1531.

The Department proceeded to set up meetings starting in December 2004 between its Consumer Assistance staff and the Company to discuss what measures could be taken to improve UI's call center performance. In the first meeting the Company suggested that the reason for the long hold times was that the new CIS system was more difficult to navigate than the old and therefore it took the representatives longer to retrieve information. The representatives also had to go back into the old system for customer history because the records could not be transferred into the new system which proved to lengthen the calls. The Company stated that it had plans to retrain the representatives and to review the transaction time for the incoming calls to see why some calls take longer.

In March 2005 the Department met again with Company to discuss the continuing long hold times and abandon rates. The Company said that it was still having problems with the system and because of the vast amount of information it provided it had proven to be more difficult for the representatives to master. The Company said it had a team in place for improving the average speed of answer (ASA) and abandoned call rate. It was also trying to identify problems with the technology and to develop strategies to implement corrective action. The Company said that it was also in the process of filling open positions in the call center and collection area and that while that was being done overtime was being utilized to minimize the impact on the customers. Tr. 10/18/05, p. 1515.

The call hold and abandoned rates began to improve in September of 2004, ten months after the new CIS system was installed. However, in July and August of 2005 the Department's Consumer Assistance staff began receiving complaints that customers were having difficulty reaching UI. Tr. 10/18/05, pp.1532 and 1533. The average hold time was 3.10 minutes and the average number of abandoned calls was 14%. The Department requested that UI resume providing weekly call center reports to the Consumer Assistance staff for its review. The Company testified that it had not sent out notices or put a message on the Voice Response Unit (VRU) to inform customers of longer hold times as it had done in 2003 when the system was installed.

***118** The Department's position is that UI should have taken quicker action to alleviate the problem of long hold times and abandoned calls and failed to do so. The Company should have adjusted schedules to have more representatives during the peak periods of the day and also on Mondays when the hold times and abandoned rates were the highest. Although it did put a message on the ACD in the fall of 2003 when the system was new it did not put a message on it when there was a renewed problem in July 2005. It appears that the Company was unprepared for the difficulties the new CIS system would present. The Company testified that it did not seek out a recruitment firm for the purpose of hiring and training new representatives. Tr. 10/18/05, pp. 1511 and 1512; Tr. 11/9/05, pp. 2154 and 2155. The Company also testified that when developing objectives for meeting the call demand before the new CIS system went on line it had not taken into consideration the possibility of representatives transferring out of the call center. It had only considered retirement. Tr. 11/09/05, p. 2167. The Company also said that its primary focus had been the quality of the call. The Company believes the customer should be satisfied so the duration of the call may not be the most appropriate customer satisfaction metric. Response to Interrogatory CA-7. ‘We don't want reps rushing a call to meet a target. We really want the call to be of high quality that when a customer is done they are very satisfied with the results.‘ Tr. 11/9/05, p. 2167. In the hearing the Company witness testified that 3-5 minutes would be an acceptable time to be on hold. Tr. 11/9/05, p. 2170. The Department believes that this is not an acceptable target time. It also suggests that there are other means to measure customer satisfaction such as complaints filed by customers to the Company. Tr. 11/9/05, p. 2183. Although the Department agrees that customers should be satisfied after they have called the Company it also believes that a customer should not have to wait on hold for an extended period of time or until he or she decide to abandon the call.

The Department believes that after two years with the new CIS system in place the Company should have worked out the difficulties with hiring and training its representatives. The staff levels have not met the call volumes. The Company claimed that it evaluates the staffing on a quarterly basis and then works with the union to make any adjustments. Tr. 11/9/05, pp. 2162-2164. The fact that the Company would not immediately evaluate this situation is troublesome to the Department. The Department also believes that once the Company started experiencing long hold times again in the summer of 2005 it should have notified its customers either by mail or by the ACD that the Company was again experiencing problems. The Department will order the Company to send monthly call center reports and to have monthly meetings with the Department's Consumer staff until such time the hold time falls to an acceptable level for at least two consecutive months.

***119** The AG has suggested that the Department set specific benchmarks for call hold times and abandoned call times for UI's customer service center. AG Exceptions, 1/19/06 p.13. The Department has not set specific benchmarks for any other utilities, and with the exception of cable television companies, there are no specific standards or benchmarks set forth in Connecticut's state statutes or regulations for such benchmarks. Therefore, the Department at this time will not set specific benchmarks for UI's customer service center. However, the Department is in agreement with the AG that the service being provided to some customers who contact UI's customer service center is unsatisfactory and must improve. The Department will continue to monitor the performance (including the hold times and abandoned call rates) at the customer service center, require monthly reports from UI on performance, meet monthly with Company management to identify the areas where deficiencies exists and where improvements need to be made and make certain that performance of the customer service center soon rises to a level that meets customer expectations for the customer service center.

2. Company's Deposit Procedures

The Company testified that it implemented a new security deposit procedure for commercial customers as part of its CIS project that went on line the week of November 10, 2003. When a deposit is received for an account, the date and amount of the deposit is now seen on the customer's bill every month. Once the deposit has been held for a year the account is reviewed by a collections' representative. If the account has been paid on time every month, the billing department will mail a refund check to the customer. Tr. 10/18/05, pp. 1527-1529. The Department notes that UI was not in compliance with order No. 14 in Docket No 01-10-10 in which UI was ordered no later than September 30, 2003, to amend its security deposit procedures to include the provision of a receipt of a security deposit to every commercial customer as required by Conn. Agencies Regs. §16-11-105(c). There is no evidence of a compliance filing under the above docket or order number.

3. Late Payments on Bills

The Department is concerned about complaints it has been receiving from customers who were incurring a late payment fee when they paid their bills at a payment agency. The Company stated in the hearing that when a customer pays on the due date and if the payment agency electronically files the payments late in the day or the next day the Company will post the payment a day later. The Department's concern is that the customer has made the payment on the due date and should not incur a late fee. The Company has recently added a message to customer's bills warning them that if they make a payment on the due date at an authorized agency that the payment might not post until the next business day. Tr. 10/18/05, pp. 1534-1537. Although the Department agrees the message might alert customers to the possibility of incurring a late fee, it does not solve the problem. The Department will order the Company to meet with the Department Consumer Assistance staff to address how the company applies late fees when a customer has paid their bill at an agency on or before the due date. The Department believes that with the new CIS system a solution can be found.

4. Customer Complaints

***120** The Company witness testified that the Company handles around 650,000 calls annually by live agents and over 300,000 through the interactive voice response unit (IVR). Tr. 10/18/05, p. 1501. The Company tracks any complaint that is escalated to a senior manager, but does not track every complaint. If the complaint is handled by a representative and the customer needs no further assistance, it is not recorded or tracked. The Company witness testified in the hearing that the Company was not tracking those complaints from customers who had been on hold for a long time. The Company witness further stated that his focus was to reduce the ASA by hiring more representatives and thereby reduce the hold time to an acceptable level. Tr. 11/09/05, pp. 2178-2180. The Company witness indicated that customers would probably experience delays as part of the learning curve on the new system, but also stated that the Company would be proactive if it receives a series of complaints on one subject. At that time it would then look to see what was causing the problem. Tr. 10/18/05, pp.1508 and1509; Tr. 11/9/05, p. 2183. The Department believes that it would be prudent on the part of the Company to track all complaints so it can collect useful information that might help it improve its customer service. But especially hold time complaints once it installed the new CIS system. The Department will order the Company to maintain and file quarterly reports on the number and types of complaints it receives.

5. Customer Satisfaction Survey

The Company stated that it hit its all time high 90.3% in customer satisfaction in the 2004 Customer Satisfaction Survey even though the ASA was over one hundred seconds. The Company believes that there is a balance between giving quality information to a customer and the operating indicator ASA. The Company believes in focusing on quality. Tr. 11/9/05, p. 2168. The Department agrees that both factors are important, however no customer should have to wait on hold for a prolonged period of time. The Department knows that only a random number of customers participate in a survey and thereby it only reflects a small percentage of the UI's customers.

IV. FINDINGS OF FACT

1. UI requested approval of a proposed Rate Plan for a period of four years through December 31, 2009, effective January 1, 2006.

2. UI proposed to increase distribution rates by$34,398,000, $39,196,000, $51,405,000 and $57,963,000 compared to current rates for the years 2006-2009, respectively.

3. UI requested a further increase in distribution rates of $2,854,000, $2,023,000, $1,988,000 and $3,592,000 for the years 2006-2009, respectively.

4. UI proposed to increase competitive transition rates by $2,562,000, $2,171,000, $2,525,000 and $2,974,000 for the years 2006-2009, respectively.

5. The requested increases equal annual increases of 5.5% for 2006, 0.5% for 2007, 1.8% for 2008 and 1.2% for 2009.

6. UI proposes to change its existing earnings sharing mechanism by retaining actual earnings above the authorized return for the first 100 basis points and sharing on a 50/50 basis additional earnings above 100 basis points over the authorized return.

7. Conn. Gen. Stat. § 16-244c(b)(2)(C) requires that an electric distribution company filing an application for an amendment of rates must include in such filing a four-year plan for the provision of electric transmission and distribution services.

8. UI used the operating results for the 12 months ended December 31, 2004, as its test year.

9. UI presented a fully forecasted rate year, 2006. In addition, pursuant to Conn. Gen. Stat. § 16-244c(b)(2)(C), UI proposed a four-year Rate Plan from 2006-2009.

10. Each year of the Rate Plan was built from the bottom up based on the projected operating and capital needs of the Company.

11. The Company currently has six separate work facilities located throughout its service territory.

12. UI plans to construct a new facility in Orange, Connecticut that will serve as a centralized worksite that will effectively replace the other worksites.

13. The application includes a $29.6 million capital expenditure during the Rate Plan period to support the consolidation of the other facilities into the Central Facility.

14. UI proposes to implement its Central Facility strategy in two phases. Relocations in conjunction with Phase 1 are planned for 2008, and those with Phase 2 are planned for 2012.

15. Phase 1 consists of construction of a 188,000 square foot building at a net capital cost of $29.6 million. Phase 2, the costs of which will be incurred after the Rate Plan period, consists of construction of an additional 147,000 square foot addition at a capital cost of $28.7 million.

16. The Company has presented two alternatives to the Central Facility plan in this proceeding: the Status Quo Plus and Decentralized Alternative scenarios.

17. The SOC is the control center where the transmission system controls and monitors are located and where distribution system switching is coordinated.

18. Floor plans for the Central Facility have not even been drafted as of this time, nor has the approach to siting the SOC been decided.

19. In a four-year Rate Plan that includes the Central Facility, UI states that the only costs that should be trued up are the capital costs specific to and attributable to the Central Facility (Phase 1) and the dollar amount of the ESWC regulatory asset.

20. The OCC's position is that UI's Central Facility plan should not be approved or included in the revenue requirements allowed in the current rate proceeding.

21. The AG states that the Department should not allow UI to collect in rates the costs associated with its proposed, but ill-defined central facility project.

22. On December 8, 2005, UI submitted a signed purchase and sale agreement for a site in Orange, Connecticut.

23. UI's response to Interrogatory EL-396, Second Supplement identifies Central Facility specific revenue requirements of $3,730,000, $4,506,000, $9,956,000 and $8,398,000 for 2006-2009, respectively.

24. UI intends to sell the ESWC in 2008 and requests to create a regulatory asset in 2006 for the projected $7.1 million loss on the projected sale.

25. The net book value of the ESWC, including leasehold improvements, will be $15.1 million at December 31, 2008.

26. When UI purchased the ESWC in 2004, the property was appraised at $8 million.

27. UI states that the regulatory asset for the ESWC could be trued up at the time of the sale of the ESWC on the basis of the actual sale price.

28. The 1994 ESWC lease provided an option for UI to purchase the building at the ten year lease point, for a pre-set price of $16 million. The lease buyout price of $16 million was less than the sum of the remaining lease payments.

29. UI proposed a 2006 average distribution rate base of $400,379,000. In addition, the average rate base for 2007-2009, respectively, is projected to be $415,998,000, $460,143,000 and $464,280,000. UI later increased the 2006 average rate base by $1,270,000 and decreased the rate base for 2007-2009, respectively by $3,897,000, $12,969,000 and $3,399,000.

30. The Company plans on increasing and enhancing equipment inspections, expanding equipment analysis and advancing the scope of its infrastructure replacement programs.

31. The value of the Company's plant added in 1966-1975, escalated to 2004 dollars, is approximately $385 million. The value of the plant added in the following 10 years, 1976-1985, is $174 million, or less than half the value of the plant referred to by the Company as aging.

32. The projected average capital additions over the term of the Rate Plan are $59.6 million, and the historical capital expenditures for 2002-2004 are $60.4 million.

33. The Company is implementing a program to eliminate older, lower voltage, high maintenance substations from its distribution system.

34. The net effect of the elimination of the substations is a savings of approximately $20,000 per year in avoided maintenance expenses.

35. The Air Circuit Breaker project consists of replacement of old substation Westinghouse DH type air circuit breakers with vacuum operated breakers.

36. The Financial System Implementation initiative provides for upgrading/replacing financial software.

37. The Rate Plan includes funding for a refreshment of desktop computers twice; once in 2006 and again in 2009.

38. The Company's filing incorrectly assigned several transmission projects to distribution, including Transmission Meters, Relay Communications Replacement, and one small reimbursable project.

39. In determining its working capital requirements, UI developed detailed revenue lead and expense lags for all significant cash inflows and outflows utilizing test year 2004 as a basis.

40. UI used the FERC-allowed percentage to allocate the rate base item for working capital to transmission.

41. UI proposed total operating expenses of $201,784,000, $209,751,000, $217,378,000 and $222,924,000 for 2006 through 2009, respectively. UI later increased its proposed operating expenses by $2,488,000, $2,078,000, $3,182,000 and $3,608,000 for 2006 through 2009, respectively.

42. UI increased advertising expense by $103,000 in 2006 and escalated for the remaining Rate Plan years for customer education and promotion of the water heater control program.

43. UI increased advertising expense in the rate year for items such as general awareness and corporate communications ($65,000), customer service technologies such as IVR and web self-service ($62,000), economic and community development programs ($48,000) and a phone book listing ($13,000).

44. The amount included in rate year 2006 for membership dues is a 120% increase from the 2004 test year level of $639,000.

45. Specific programs and organizations funded by membership dues expense include the Connecticut Economic Resource Center (CERC) for $200,000 and Bridgeport Economic Resource Center (BERC) for $36,000.

46. UI testified that the Company will commit to funding CERC and BERC if the Department allocates a specific line item to these organizations.

47. The Company is increasing its Line Clearance expense from $1,479,000 in 2004 to $2,266,000 in 2006.

48. The expanded line clearance program includes three major changes in the vegetation management program: a new program to remove vines that threaten electric facilities; A new program to remove hazardous trees outside the normal trim zone; and expansion of the trim zone around conductors.

49. The Department provides a report to the Legislature on electric distribution company service reliability each year, in accordance with Conn. Gen. Stat. §16-245y. In its most recent report dated June 15, 2005 in Docket No. 05-05-05, the Department found ' …that UI's reliability has declined slightly since 1998'.

50. Tree/vegetation contacts are the second leading cause of outages in UI's system, next to equipment failure.

51. The 2004 expense for spot trimming activities is $135,000, and the proposed 2006 rate year expense is $259,000.

52. Beginning around 2003, UI experienced several large-scale outages that originated from vines contacting electric lines.

53. UI's hazard tree removal program provides for removal of trees that are located outside the normal trim zone, and are dead, dying, diseased or structurally defective, and also present a potential hazard to electric distribution facilities.

54. In 2003, 2004 and 2005, the Company made no charges to the Storm Reserve Account.

55. The Governors of the U.S. Postal Service have accepted the recommendation to increase most postal rates and fees by 5.4% effective January 8, 2006, including an increase in the rate for first-class mail from 37 cents to 39 cents.

56. UI has hired a broker to look into opportunities to sublease out the additional approximately 5,000 square feet of space that will not be occupied in the new lease.

57. Since 2002, the annual telecommunications expense has declined from a high of $1,802,000. However, 2006 includes costs for new telecommunications systems.

58. UI plans to hire incremental Electric System workers in anticipation of the future retirement of workers who are or will be eligible for retirement in the next several years.

59. In 2004, the Company conducted a study of the resource needs to address attrition in the skilled technical positions, including lineworkers. This study assumes that 33% of eligible employees will retire in their year of eligibility.

60. In 2005, 109 of Electric System workers are eligible for retirement, which equates to 31% of all lineworkers.

61. UI has three incentive compensation plans, Management Compensation Program (MCP), Executive Incentive Compensation Program (EICP) and Executive Long-Term Incentive Program (LTIP).

62. The MCP consists of corporate, division, and team/individual goal results.

63. The EICP consists of financial goals and the UI and division scorecards.

64. The LTIP is a performance share program and consists of the average of the earned return achieved each year of the three year program.

65. Incentive Compensation costs are budgeted assuming achievement at the target level on a Company-wide basis each year.

66. For the 2004 test year, UI's Incentive Compensation totaled $5,429,000.

67. The Incentive Compensation currently allowed in rates is $3,539,000.

68. UI's proposed incentive compensation is escalating at a rate of 3.8% to 4.8% per year.

69. UI's incentive compensation payments vary based on achieved goals.

70. The Company's 2002-2004 three-year average for incentive compensation payments total $3,994,000.

71. UI's 2006 through 2009 proposed incentive compensation amounts represent an increase of 41%-61% over the three year average.

72. For test year 2004, UI's capitalized overhead totaled $2,682,000. The Company has proposed $1,996,000-$1,808,000 for rate years 2006-2009, respectively.

73. Historically, the Company's capitalized overhead have ranged from $1,861,000-$2,632,000 for the years 2000-2004.

74. The Company's year to date capitalized overhead as of August 31, 2005 was $1,946,000. This amount annualized is $2,919,000.

75. For test year 2004, UI's overtime and premium payroll totaled $5,399,000. The company proposed $4,976,000-$5,494,000 for the rate years.

76. In the years 2000-2004, UI's overtime and premium payroll have ranged from $3,418,000 to $5,647,000.

77. Overtime and premium payroll have increased significantly since 2001.

78. As of August 31, 2005, the Company has incurred $4,090,000 in overtime and premium payroll. This amount annualized totals $6,135,000.

79. UI's 2004 test year distribution compensation expense for 616.1 Full Time Equivalents (FTEs) totaled $46,817,000.

80. The Company's proposed 2009 compensation expense is $20,780,000 over the 2004 test year level and represents the amounts identified as being charged to distribution O&M expense.

81. UI is proposing a compensation expense of $57,460,000 for 2006, $61,674,000 for 2007, $64,670,000 for 2008, and $67,597,000 for 2009.

82. UI is proposing an O&M FTE increase of 108.9 FTEs.

83. Approximately 40% of the Electric System workforce will be eligible for retirement by 2009. The Electric System business area expects approximately 33% of the eligible employees to retire.

84. Annual retirements are projected to range from 13.2% to 14.9% of eligible employees over the period 2005-2009. The Company indicated that historically 12% have retired.

85. The Company's net compensation expense (excludes incentive compensation) proposal ranges from $51,811,000 in 2006 to $61,179,000 in 2009. This level of expense is for 703.6 FTEs in 2006 and increasing to 725 in 2009.

86. UI projected 27 FTE retirements for 2005. As of August 15, 2005, the Company has had 20 retirements this year.

87. UI's FTE level as of September 30, 2005 totaled 673. This level grossed up by the Company's 3.1% vacancy rate equals 694 FTE's. This figure exceeds the Company's 2005 projection of 684.

88. UI's average salary per FTE for rate years 2006 through 2009 range from $73,637 to $84,385, respectively.

89. UI's 2002 average salary per FTE was $62,763.

90. 33% of UI's staff should have retired in the years 2003-2005 and another 33% should retire through 2009.

91. UI's actual distribution compensation expense (less incentive compensation) as of August 31, 2005, was $29,644,000 ($33,315,000 - $3,671,000). This amount annualized equates to $47,056,575. This estimate is based on 657 employees for eight months and 684 employees for four months. The estimate is $1,722,425 less than the Company's 2005 projection of $48,779,000.

92. Increases in health care benefit costs continue to grow at a double-digit rate.

93. For 2005, UI has made structural changes in the pension and other post retirement employee benefit (OPEB) plans.

94. Effective April 1, 2005, for those hired into the bargaining unit and on May 1, 2005, for all other new employees, UI has implemented a new retirement plan that replaces the existing qualified pension plan and retiree medical plan benefits for new employees.

95. The retirement plan for new employees will be a defined contribution plan, consisting of the current provisions of the 401(k) stock ownership plan (KSOP) for both pension and post-retirement medical benefits.

96. UI subsequently revised pension and OPEB expense based on more current assumptions as of October 27, 2005 and thus the Company's revised pension and OPEB expenses requested in rates are as follows: updated total pension expense of $14.4 million, $10.4 million, $10.3 million and $8.6 million, and revised total OPEB costs of $5.1 million, $4.6 million, $4.45 million and $4.24 million, for the Rate Plan years 2006-2009, respectively.

97. The Company's final pension and OPEB expense for 2006 was recalculated as of October 27, 2005, using a discount rate of 5.5% which was Moody's Aa rate at that date.

98. The Company used an 8.0% expected return on assets assumption for all years of the Rate Plan period.

99. In calculating its requested pension and OPEB expense, the Company assumed a 65%/35% equity/ fixed split in its investment mix compared to a 70% equity investment position for previous years.

***121** 100. In the Company's filing it has used an average wage increase assumption of 4.5% for all years of the Rate Plan period.

101. The same discount rate and expected return on plan assets are used to calculate OPEB expense.

102. The Company also uses a healthcare trend rate assumption for pre-65 and post-65 retirees of 11% and 6% for 2006 and grading down 1% each year to 10% and 5.5% for 2007, 9% and 5.0% for 2008, and 8% and 5% for 2009, respectively.

103. As of October 27, 2005, the Treasury 20-year Constant Maturity Treasury Index (CMT) was 4.84%, a 56 basis points increase from 4.28% at June 24, 2005.

104. The Department evaluated the Treasury 20-year CMT rate as of the last day of hearings, November 9, 2005, and found that this rate was 4.93% versus 4.28% at June 24, 2005, a 65 basis points increase.

105. UI indicated that its original calculations were based on an expected asset level of $294.7 million at year end 2005.

106. Using the S&P 500 as a reasonable proxy for equity performance, the index had risen to 1,220.65 on November 9, 2005 from 1,178.89 at October 27, 2005.

107. As of October 27, 2005, the expected OPEB asset level was approximately $24.9 million for year end 2005 compared to UI's original calculation of $25.9 million.

108. UI used a pre-65 healthcare trend rate assumption of 11% in 2006 trending downward to 8% in 2009.

109. UI is seeking full recovery of its matching contributions made by the Company to the 401(k) Employee Stock Ownership Plan along with incremental contributions for new employees in lieu of their participation in the pension and OPEB plans.

110. UI projects the full amount of KSOP contributions to be $2.782 million in 2006, $3.117 million in 2007, $3.465 million in 2008, and $3.788 million in 2009.

111. UI submitted a new depreciation study in this proceeding. The Company last submitted a depreciation study to the Department in Docket No. 89-08-11. That study was conducted in 1988.

112. The depreciation study uses the straight-line method, remaining life technique and vintage/broad group method, or average life group, for compiling depreciation of each type of plant.

113. The total plant level average service life in the study was 34.1 years, compared to the average service life of 34.4 years in the 1988 study.

114. The depreciation study includes a recommendation to increase the net salvage in Account 364 from -15% to -25%.

115. The depreciation study includes a recommendation to increase the average service life in Account 366 from 65 years to 75 years.

116. The depreciation study includes a recommendation to increase the net salvage in Account 369 from -20% to -40%.

117. The depreciation study includes a recommendation to reduce the average service life in Account 370 from 30 years to 25 years.

118. The depreciation study includes a recommendation to decrease the net salvage in Account 372 from +20% to zero.

***122** 119. The depreciation study includes a recommendation to decrease average service lives in Account 390 from the 50 years recommended in the prior study, to 35 years.

120. The Company proposed a capital structure consisting of 52% equity and 48% debt to be utilized for each year of the Rate Plan.

121. At the time of filing the Company's rate case application, UI's actual capital structure was approximately 48% equity and 52% debt.

122. UI's currently allowed capital structure is 47% equity and 53% debt.

123. For years 2006 through 2009, the Company's average forecasted long-term embedded cost of debt is estimated at 4.24%, 4.26%, 4.79% and 5.66%.

124. UI's Order No. 1 compliance filing for the 12 months ended September 30, 2005, in Docket No. 76-03-07, the Company shows that its embedded cost of debt was 4.20%.

125. The Company advocated an allowed rate of return on equity (ROE) of 11.6%, including an additional upward adjustment to the ROE of 20 basis points for flotation costs associated with the new equity.

126. Dr. Avera's testimony was based on various risk premium methods and DCF analysis of seventeen comparable (proxy group) utilities.

127. The cost of equity estimates produced by Dr. Avera's application of the multi-stage DCF model averaged 10.6%.

128. Based on the results of Dr. Avera's analyses and assessments, he concluded that the cost of equity for the proxy group is in the 10.9% to 11.9% range, excluding an adjustment for flotation costs.

129. The OCC's witness cost of equity recommendation in this proceeding was 8.60% based on the capital structure containing 50%/50% capitalization and an overall fair rate of return of 6.43% for Rate Plan years 2006 through 2009.

130. The OCC's cost of equity witness, Dr. Woolridge, employed the use of the DCF and CAPM approaches to two groups of electric utility companies.

131. Combining all the components of the DCF model, Dr. Woolridge calculated an equity cost rate of 8.49% for proxy Group A and cost of equity of 8.74% for Group B.

132. Dr. Woolridge arrived at a CAPM equity cost rate of 7.8% for his two proxy groups.

133. Given his DCF and CAPM equity cost rate results, Dr. Woolridge concluded that a fair equity cost rate for UI is 8.6%.

134. The Company is requesting 20 basis points for flotation costs.

135. At the time of UI's last rate setting proceeding, yields on 20-year treasury bonds were 5.25%.

136. The current 20-year treasury yield is currently about 4.5%.

137. By year-end 2002, UI shed its remaining interests in its nuclear assets.

138. A tax law was passed in late May 2003, that lowers the federal income tax rate on dividends to 15%, and the tax on long-term capital gains has been reduced from 20% to 15%.

139. The Department reviewed its own recent ROE awards and found the following: The Connecticut Light and Power Company, 9.85% ROE in 2003, Southern Connecticut Gas Company, currently proposed for settlement at 10.0% as brought out at a October 20, 2005 Hearing, Yankee Gas Service Company 9.9% ROE in 2004, Aquarion Water Company, 9.75% ROE in 2005, and Crystal Water, 9.9% ROE in 2005.

***123** 140. Based on the first six months of 2005, the national average electric equity return authorization by state commissions was 10.36% as reported by the Regulatory Research Associates, Inc.

141. UI has not filed a COSS since 1992.

142. This is the first time that UI is filing a cost of service study since electric restructuring began in 1998.

143. In the cost of service study UI analyzed and arrived at rates of return for those functional components of UI's rates which are assigned rate base, revenues and expenses.

144. UI used the minimum intercept method to allocate distribution costs to rate classes.

145. There are large differences in the overall rate of return between rate classes.

146. Through 2004, UI has a cumulative CTA underrecovery of $29.75 million.

147. UI currently collects many costs that could be deemed GSC related through the distribution rate.

148. The true cost of supplying generation is not readily known because some GSC costs are embedded in the distribution rate.

149. All customer bill inserts are not in both English and Spanish.

150. UI has continuing long hold times and a high number of abandoned calls since the new CIS system was installed in November 2003

151. UI did not comply with Order No. 14 in Docket No. 01-10-10 by the specified date of September 30, 2003.

152. UI was found to be in compliance with Conn. Agencies Regs. §16-11-105(a) the policies and procedures for the administration of customer security deposits as of November 10, 2003 when its new CIS system went live.

153. UI customers are incurring late fees on their bills when paying at a payment agency on the date the bill is due.

154. The number of staff in the Client Relation Center is insufficient to handle the call volume.

155. The Customer Satisfaction Survey is not the only metric to measure customer satisfaction.

156. The Company did not put a message on the ACD when it again began to experience long hold times in July and August of 2005.

157. The Company did not keep a record of hold time complaints. It only keeps a record of complaints that are escalated to management.

158. The Company did authorize overtime for its Customer service representatives in an attempt to alleviate long hold times and abandon call rates.

V. CONCLUSION AND ORDERS

A. CONCLUSION

The Department concludes that, with the revenue requirement adjustments as authorized herein, the Company's revenues will be sufficient to enable the Company to operate successfully, maintain its financial integrity, attract capital, compensate its investors for the use of their money and the risks assumed, and maintain high quality service.

The Company had requested a total of $64.5 million revenue requirement increase over the four years of the rate plan. The Department reduced the Company's proposed incremental revenue requirements by a total of $28.9 million over the four years of the rate plan from that requested. The Department does not increase rates associated with the recovery of competitive transition assessment revenue requirements. The incremental revenue requirements approved by the Department for the years 2006, 2007, 2008 and 2009 are as follows: $14,324,000, $4,302,000, $10,263,000 and $6,710,000, respectively. The allowed increases translate into total company increases compared to then-current rates of 1.98% in 2006, 0.6% in 2007, 1.4% in 2008 and 0.9% in 2009. The Department further allows UI an ROE of 9.75%. The Company's cost of capital will be based on an allowed capital structure containing a 48% common equity component and 52% debt capitalization component.

***124** The Department allows UI an earning sharing mechanism ESM that provides for a 50/50% (Company/ratepayers) sharing of earnings above UI's allowed ROE of 9.60%. In this regard, 50% shall be retained by the shareholders of UI, 25% will be returned to the customers of UI through bill surcredits, and the remaining 25% will be used to reduce the customer's balance of stranded costs.

B. ORDERS

1. On or before February 7, 2006, UI shall submit tariffs to comply with the directives contained herein. The Department will allow UI to increase residential Rate R rates by 3.0% in 2006 and Rate RT by the average of 1.98%. Rates GST and LPT shall be increased by 1.0% and Rate M and Rate U by .75%. The Department will approve rate increases to other rate classes as proposed but adjusted to reflect the allowed average rate increase.

2. Not later than January 30, April 30, July 30 and November 30 of each year beginning April 30, 2006, UI shall file reports on the Central Facility status as of the end of the prior calendar quarter. At a minimum, the report shall include any changes to the construction schedule, finalization of floor plans, construction status, and relocations of personnel from other facilities into the Central Facility. This order expires with the report that states that Phase II construction is complete and all applicable personnel have relocated from other UI facilities to the Central Facility.

3. UI shall file the actual capital costs for the Central Facility when construction of Phase 1 is completed. The filing shall also include remaining capital costs and actual to date and projected O&M expenses for the Rate Plan period. The filing shall include an itemization and description of all costs and shall identify rate base and expense impacts. The Company shall include support for projected capital and O&M expenses as is available, including contracts. In addition, coincident with the status reports filed no later than July 30, 2006, 2007 and 2008, UI shall provide the Department with an update of its actual and projected remaining capital and O&M expenses for the Central Facility.

4. UI is to create a regulatory asset or liability for the variance in actual prudent Central Facility Phase I capital and O&M costs compared to the amounts allowed herein.

5. In its next rate application, UI shall request disposition of the Central Facility regulatory asset or liability.

6. In future lead/lag studies to be filed by UI, itemized expenses shall reflect proposed distribution expenses, not including transmission-related expenses, along with the working capital requirements associated with energy supply contracts not otherwise reflected in GSC rates.

7. UI shall spend minimally $255,000 of its annual membership dues budget for CERC dues and $36,000 for BERC dues.

8. The Company shall file a complete updated depreciation study with its first rate application that is filed after January 1, 2009.

9. By March 30 of each year 2006, 2007, 2008, and 2009 the Company shall report to the Department on the hiring of new Electric System personnel and on the retirements during the preceding year. At a minimum, the report shall include the number of new hires, retirements, terminations and transfers by job category.

10. No later than October 1, 2006, UI shall file a full cost study including all of its rate components. The study shall incorporate the changes discussed in Section III.J.3.

11. No later than March 10, 2006, the Company shall file a monthly report that contains the following information from the Client Relation Center.

***125** • The amount of overtime hours authorized and the number of employees authorized overtime for the.

• The number of employees at the beginning of the month, number of employees hired during the month, the number of employees terminated during the month, the number of employees who retired during the month, the number of employees who left during the month as a result of a promotion or transfer and the number of employees out on an extended leave during the month.

• The number of people in training. The number of people you have in your candidate pool (eligible to be hired in the CRC). The current schedule dates for training.

• File weekly reports with the Department showing for each day of the week that the report is being filed for:

The total number of calls received

The total number of calls handled by the ACD.

The total number of calls that required a live customer service representative and for those calls:

The total number of calls abandoned

The % of calls of abandoned

The average hold time (in seconds)

The number of full-time customer representatives taking those calls

The number of part-time customer representatives taking calls.

The ratio of total calls to representative

Total number of busy signals

• The total number of customer complaints pending and the total number of DPUC referred complaints. The report is to be filed no later than 5 days after the close of the period for which the report is being submitted.

12. No later than March 1, 2006, UI shall file with the Department its target objectives for daily average staffing levels for a typical Monday, Tuesday, Wednesday, Thursday, and Friday.

13. No later than March 1, 2006, UI shall file with the Department target objectives for abandoned call rate, average hold time, ratio of calls to customer representatives and average number of busy signals.

14. No later than March 1, 2006, UI shall file with the Department the number of employees it expects (or estimate) to lose in the CRC for the next 3, 6, 9, 12, and 24 months. UI shall file the number of new employees it expects to introduce into the CRC for those same periods.

15. No later than March 1, 2006, UI shall file a report on the actions it has taken, or is considering, to better match the number of employees taking the calls with the number of calls that come into the Call Center.

16. No later than March 1, 2006, UI shall file report on any actions or discussions within the Company to use outside firms to assist with recruitment, testing, or placement of employees.

17. Other than the Customer Survey, provide a copy of the Company's other metrics that it uses to measure the satisfaction of customers who call or write to the CRC.

18. By March 1, 2006, the Company shall file a copy of the draft message that will be put on the ACD to inform customers of the expected length of the hold time along with a description of the circumstances that will trigger the message being activated.

19. No later than February 15, 2006, the Company shall begin monthly meetings with the Consumer Assistance staff.

20. All customer bill inserts shall be in both English and Spanish. The due date to make the changes will be determined at the first meeting between UI and the Consumer Assistance staff.

21. By March 1, 2006, the Company shall file a report on any new technologies the Company plans to deploy in the CRC Center.

22. Beginning on March 1, 2006, through March 1, 2007, respectively, UI shall maintain and begin filing quarterly reports on the number and types of complaints and inquiries (use the categories contained in UI's Late Filed Exhibit No. 74) being received in the CRC. Provide a copy of the form on which those complaints and inquiries will be recorded.

23. No later than April 1, 2006, the Company and the Consumer Assistance unit shall meet on a mutually agreed date to have UI demonstrate the test given to the call center candidates.

24. No later than April 1, 2006, the Company and the Consumer Assistance unit shall meet on a mutually agreed date to address how the Company applies late fees to a customer's bill when the customer paid at a payment agency.

25. No later than March 1, 2006, the Company shall begin keeping record of any complaints it receives from customers who have been on hold for a long period of time. The complaints shall have the customer's name and address. This record shall be submitted on a monthly basis to the Department and shall be kept for the next twelve months.

.SK 12

Footnotes

1 Electric System Work Center.

2 Supplemental Response to Interrogatory EL-34.

3 Northeast Electric Reliability Council and Northeast Power Coordinating Council.

4 Components having changes that indicated a relatively minor effect on working capital (*e.g.* >$10,000) were not adjusted for.

5p

Working Capital Component	**2006**	**2007**	**2008**	**2009**
Storm Reserve	61	61	61	63
Technology	23	23	23	27
Professional Services	(29)	(29)	(30)	(27)
Facility Rent	12	13	14	14
DOL Insurance	235	250	250	252
Medical Insurance	45	42	73	101
Payroll & Incentives (incl. UIL)	102	116	130	165
Sublease Income	37	41	42	46
ESWC Asset Amortization	90	90	90	94
Gross Earnings Tax	(113)	(116)	(126)	(127)
Depreciation	(29)	18	11	1
	——	——	——	——

Working Capital Decrease	**434**	**509**	**538**	**609**

5 The Electric System includes the UI job classifications of power delivery lineworkers, substation electricians, engineers, electrical test technicians and system operators.

6 The distribution FTE level was calculated at 76.7% of UI's total FTE level.

7 2006 Average salary per FTE computed as follows: $57,460,000-$5,649,000/703.6.

8 It should be noted that on page 58 of the 01-10-10 Decision, the Department stated, ‘it is apparent that majority of the employees with 30 years of UI service will be replaced by lower paid employees. This will impact 33% of UI's workforce and will certainly reduce payroll expense. Furthermore, any hiring that overlaps with the retiring employees is a non-recurring expense and should be for a short period of time.‘

9 Payroll expense of *$24,989,908 less incentives of $745,443* divided by the proposed level of FTEs equal to 332.

10 Schedule WPC-3.2. Total Wages of *$19,890,977* divided by 323.6 employees.

11 Test year 2004 *pro forma* medical expense was $4.130 million based on a per-employee medical cost of $7,134 million. The increase in cost from the 2004 *pro forma* cost and the projected 2009 cost results in a 195% medical cost increase over the five-year period.

12 There is a successor to this report entitled *Managing Health Care Costs in a New Era: 10th Annual National Business Group on Health/ Watson Wyatt Survey Report 2005* (W/W Survey). *See* http:// www.watsonwyatt.com/research/resrender.asp?id=w-821&page=1. In the W/W Surveys' Executive Summary, it states ‘[a]n increasing number of employers are seeking to engage employees through consumer-directed approaches and health management as part of their effort to slow rising health care costs. And some employers are succeeding — driving increased employee accountability and responsibility in health care decision-making and keeping cost increases remarkably low.‘ The W/W Survey indicates that average health care benefit costs are still rising at double-digit rates (similar to the 2004 study), though the rate of increase is slowing. The W/W Survey goes on to indicate that ‘[b]est-performing companies maintain a high level of employee satisfaction and *have a two-year median cost increase of only 5 percent — a full ten percentage points lower than their poor-performing peers*.‘ Emphasis added. Further, ‘[b]est performers set strategy based on quantitative analysis, engage consumers through information and tools, and focus on health management and lifestyle behavior change.‘ ‘Employer interest in health savings accounts (HSAs) is growing. Eight percent of surveyed organizations are currently offering HSAs, 18 percent are planning to offer them in 2006 and 47 percent are considering offering them.‘ W/W Executive Summary. Although not in the record here, the W/W survey serves to confirm the downward cost trend identified in the 2004 report.

13 ‘It is unfair and unsound to have swings in life estimates of 33% to 50% or more based on only one study‘. Study, p. 7.

14 The weighted cost is based on the proposed 52% equity capitalization and 48% debt capitalization, although the actual capitalization may vary slightly from the proposed capital structure.

Proposed 2006 Average Capitalization

	($000)	% of		Weighted
Class of Capital	Amount	Total	Cost	Cost
Long-Term Debt	420,460	47.98%	4.24%	2.04%
Common Equity	455,939	52.02%	11.60%	6.03%
	——	——		——
Total	876,399	100.00%		8.07%

Source: Schedule D-1.0 A

Proposed 2007 Average Capitalization

	($000)	% of		Weighted
Class of Capital	Amount	Total	Cost	Cost
Long-Term Debt	433,460	48.44%	4.26%	2.05%
Common Equity	461,437	51.56%	11.60%	6.03%
	——	——		——
Total	894,897	100.00%		8.08%

Source: Schedule D-1.0 B

Proposed 2008 Average Capitalization

	($000)	% of		Weighted
Class of Capital	Amount	Total	Cost	Cost
Long-Term Debt	446,460	48.48%	4.79%	2.30%
Common Equity	474,431	51.52%	11.60%	6.03%
	——	——		——
Total	920,891	100.00%		8.33%

Source: Schedule D-1.0 C

10P

Proposed 2009 Average Capitalization

Class of Capital	($000) Amount	% of Total	Cost	Weighted Cost
Long-Term Debt	445,960	48.03%	5.66%	2.72%
Common Equity	482,542	51.97%	11.60%	6.03%
Total	928,502	100.00%		8.75%

15 A typical ratcheted charge is one that the customer pays each month based on the peak consumption (demand) during a rolling time period, usually a 12-month period. This charge is assessed regardless of actual demands in a billing period.

16 In the past, SNET and UI had an arrangement regarding pole attachment revenues. UI and SNET share joint ownership of thousands of poles in UI's service territory. As a result, UI and SNET determined that it was practical to have one company administer the recovery of pole attachment revenues. SNET administered this program, billing for UI's portion of these revenues under the SNET pole attachment tariff. SNET would then flow the appropriate share of pole attachment revenues to UI. Recently, UI began billing for its own pole attachment revenues, using the SNET charge as the basis for this fee. Therefore, UI does not have a pole attachment tariff.

End of Document

WISCONSIN

Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates, Docket No. 3270-UR-115, WISCONSIN PUBLIC SERVICE COMMISSION, Final Decision (Dec. 18, 2008).

2008 WL 5435884 (Wis.P.S.C.)

Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates

3270-UR-115

Wisconsin Public Service Commission

Date Mailed December 18, 2008

FINAL DECISION

BY THE COMMISSION:Sandra J. Paske, Secretary to the Commission

This is the Final Decision regarding the application of Madison Gas and Electric Company (MGE or applicant) to reopen docket 3270-UR-115, in order to update certain costs and establish new electric rates for 2009.

A rate decrease in the amount of $2.7 million, a 0.74 percent annual decrease, is authorized for electric operations for the 2009 test year.

Introduction

On May 7, 2007, MGE filed an application with the Commission requesting authority to change its electric and natural gas rates on January 1, 2008. On December 14, 2007, the Commission issued a *Final Decision* in this docket that established rates for service beginning January 1, 2008, a forecast of fuel costs, and the appropriate fuel cost monitoring level including variance ranges. The *Final Decision* also authorized MGE to request a reopening of this docket limited to the following items: (1) monitored fuel rules costs; (2) Elm Road Generating Station (ERGS) payments and other operation and maintenance (O&M) expenses resulting from ERGS Unit 1 becoming operational in 2009; (3) an updated American Transmission Company, LLC (ATC) Network Service Fee; (4) the accrual of carrying costs at the weighted cost of capital, for future environmental upgrades at the Columbia Energy Center (Columbia) upon the Commission's approval of the upgrades, until the effective date of the *Final Decision* in MGE's next full rate case; and (5) a review of MGE's rate design to provide price signals for reducing greenhouse gas emissions.

On May 30, 2008, MGE filed an application requesting a limited scope reopener to adjust electric rates in the amount of $25,460,000 (a 6.99 percent increase) beginning January 1, 2009, for the following items:

1. Electric fuel costs monitored under fuel rules for 2009;

2. ERGS lease payments, O&M costs, and carrying costs in 2009;

3. An update of the ATC Network Service Fee for 2009; and

4. A potential update of the 2009 O&M costs associated with Columbia environmental activities that were not in MGE's 2008 rates.

On August 22, 2008, MGE lowered the amount requested from $25,460,000 to $12,275,000 (a 3.37 percent increase). In addition, MGE requested to add a pension and supplemental retirement cost update as a reopener item. On September 11, 2008, MGE provided an update to the pension and supplemental retirement cost information, increasing its overall requested increase in electric rates to $12,856,000 (a 3.53 percent increase). Also on September 11, 2008, International Brotherhood of Electrical Workers (IBEW) Local 2304 requested that the 2009 revenue requirement be adjusted for increased expenses related to comprehensive workforce planning.

On August 26, 2008, a prehearing conference was held to determine the issues that would be addressed in this docket and to establish a schedule for the hearing. A hearing was held in this proceeding on October 2, 2008, in Madison. The issues in this docket are:

1. What is the appropriate level of test year monitored fuel costs?

2. What is the appropriate level of ERGS costs?

3. Should the forecast of Network Transmission Services costs be updated to reflect ATC's fall cost update?

4. What are the appropriate revenue allocation and rate design to collect the increased costs identified in this reopener?

5. Should increased pension and post-retirement medical costs be included in revenue requirement?

6. Should increased comprehensive workforce planning expenses be included in the revenue requirement?

MGE filed a brief on October 16, 2008. IBEW Local 2304 filed a reply brief on October 23, 2008.

Findings of Fact

1. It is reasonable to allow MGE to decrease its rates for Wisconsin retail electric service in the amount of $2.7 million to reflect reduced test year fuel costs and ERGS-related costs.

2. It is reasonable to maintain, for test year 2009, the revenue requirements established for test year 2008 in the Commission's *Final Decision* of December 14, 2007.

3. It is reasonable in this proceeding to reduce monitored fuel costs by approximately $12,887,000 to reflect the New York Mercantile Exchange (NYMEX) natural gas futures strip as of November 14, 2008.

4. Fuel cost adjustments that decrease test year fuel costs by $10,204,000 from MGE's filed level are reasonable.

5. A test year fuel rules cost of monitored fuel of $123,239,000 is reasonable.

6. It is reasonable to monitor fuel costs using the following ranges: (1) plus or minus 8 percent monthly; (2) cumulative monthly ranges of plus or minus 8 percent for the first month, plus or minus 5 percent for the second month, and plus or minus 2 percent for the remaining months of the year; and (3) plus or minus 2 percent for the annual range.

7. It is reasonable to authorize the impact of the later ERGS projected start date and to defer for future return to ratepayers any delay damages that MGE recovers under the facility lease, net of any external incremental costs of recovering such damages.

8. It is reasonable to reduce the ATC Network Service Fee costs by a total of $756,000. This amount includes deferred refunds for 2008 totaling $468,000.

9. It is reasonable to deny current recovery of estimated increased 2009 pension costs for the electric utility, but approve deferral accounting for both the natural gas and electric utilities, with carrying costs at the short-term debt rate.

10. It is reasonable not to adjust the 2009 revenue requirement for increased expenses related to comprehensive workforce planning.

11. It is reasonable to approve the rates for electric service and the test year forecasted customer class changes in revenue as shown in Appendix B.

Conclusions of Law

The Commission concludes that it has jurisdiction under Wis. Stat. §§ 1.11, 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, 196.395, and 196.40 and Wis. Admin. Code chs. PSC 113, 116, and 134, to enter an order authorizing MGE to place in effect the rates for electric service set forth in Appendix B, subject to the conditions specified in this Final Decision.

Such rates for electric service in Appendix B are reasonable and appropriate as a matter of law.

Opinion

Applicant and Its Business

MGE is a public utility, as defined in Wis. Stat. § 196.01(5), operating as an electric and natural gas utility in Wisconsin. MGE is engaged in the production, transmission, distribution, and sale of electric energy to approximately 137,000 retail customers in Madison and the surrounding area in Dane County, and in the purchase, transportation, distribution, and sale of natural gas to approximately 138,000 customers in Madison and the surrounding area in Dane County, as well as in Columbia, Crawford, Iowa, Juneau, Monroe, and Vernon Counties. MGE is an operating subsidiary of MGE Energy, a holding company based in Madison, Wisconsin.

Fuel Costs

Commission staff based its estimate of natural gas-fired and purchased power costs on NYMEX natural gas futures prices that were more current than those used in MGE's filing, and proposed various adjustments which decreased the electric fuel costs from MGE's forecasted amount by approximately $10,204,000. On November 19, 2008, MGE filed a delayed exhibit reflecting decreased fuel costs of $12,887,000 resulting from updating the NYMEX natural gas futures strip from the August 13, 2008, futures strip used by Commission staff, to the November 14, 2008, futures strip, which was the most recent available mid-month NYMEX natural gas futures strip. It is reasonable to reflect the effect of this delayed exhibit in 2009 monitored fuel costs. The Commission also considers Commission staff's fuel cost adjustments, which decrease test year monitored fuel costs by $10,204,000 from MGE's filed level, to be reasonable.

A reasonable test year level of monitored fuel costs is $123,239,000, which reflects the cost of generation and purchased energy, less the revenues from opportunity sales of energy and capacity. This test year fuel cost, divided by the test year estimate of native energy requirements of 3,483,170 per megawatt-hour, results in an average net monitored fuel cost per kilowatt-hour of $0.03538.

Any cost for purchased capacity that is required to meet reserve requirements is excluded from monitored fuel rules costs and may only be adjusted in a full rate case. Firm transmission associated with excluded capacity purchases, fuel and ash handling, and sulfur dioxide allowance costs are excluded as well. Appendix C shows the monthly fuel costs to be used for monitoring purposes.

It is reasonable to monitor MGE's fuel costs using the following ranges: (1) plus or minus 8 percent monthly; (2) cumulative monthly ranges of plus or minus 8 percent for the first month, plus or minus 5 percent for the second month, and plus or minus 2 percent for the remaining months of the year; and (3) plus or minus 2 percent for the annual range.

The method of applying these ranges, established in prior Commission decisions for MGE, shall continue to be used and applied, using the data in Appendix C for monitoring fuel costs.

ERGS Lease Payments and Other Expenses

MGE originally requested an increase for 2009 of approximately $3.5 million based on an assumed commercial operation date for ERGS Unit 1 of September 1, 2009. The projected start date later changed to December 29, 2009, causing MGE to withdraw its request for an ERGS-related increase in 2009. The non-fuel effect of the new start date was to change a $3.5 million increase in ERGS-related costs to a $1.0 million decrease in costs, a net reduction of $4.5 million in ERGS-related revenue requirement. The fuel cost effect of this delay was to increase MGE's fuel costs by approximately $5.3 million. It is uncertain at this time whether MGE may be entitled to delay damages pursuant to the ERGS facility lease. The uncertainty stems from the fact that the contractor has indicated the delay is due, at least in part, to severe weather over the past two years. Under the facility lease, MGE would not be entitled to delay damages if the delay is due to a *force majeure* event.

Due to the uncertainty regarding whether MGE may be entitled to damages as a result of the later start date, MGE shall defer for future return to ratepayers any delay damages recovered under the facility lease, net of any external incremental costs of recovering such damages.

ATC Network Transmission Service Costs

At the time of MGE's original reopener filing, ATC projected its Network Service Fee for 2009 to be $521,000 higher than the amount approved in this docket for 2008. During 2008, however, MGE received a 2007 refund of $143,000 and a $325,000 reduction in the capital expense estimate for 2008. MGE proposed to return these two amounts to ratepayers as an offset against the anticipated increase of $521,000. The net effect was an increase of $54,000, which MGE offered to forgo. On October 1, 2008, ATC updated its estimate of the fee for the upcoming year. The updated estimate for 2009 is a reduction of $288,000 compared to the amount in rates for 2008. It is appropriate, therefore, to reduce the ATC Network Service Fee by $756,000 for 2009. This reduction includes deferred refunds for 2008 totaling $468,000.

Pension and Post-Retirement Medical Costs

In 2007, in the original base rate case, MGE asked that increased pension and supplemental retirement costs be included in the reopener for 2009. The Commission, however, denied MGE's request and did not identify this topic as an issue in its December 14, 2007, *Final Decision*. MGE renewed its request in this reopener.

At the time of hearing, MGE estimated the 2009 total company increase in pension costs to be in the range of $1,877,000 to $3,577,000, with the most likely scenario being an increase of $2,816,000. The electric utility's portion of these increased costs was estimated to be $1,802,000. This estimate was based on an assumed long-term return on assets of 8.5 percent and represents an increase of $908,000 between the time of MGE's original filing on this issue and its supplemental filing on September 11, 2008.

MGE requested current recovery in 2009 of increased pension and supplemental retirement costs for only the electric utility. Because the Commission did not reopen this docket to examine the rates of the natural gas utility, MGE requested deferral accounting treatment for the natural gas portion of such increased costs. As a second option, if the Commission did not grant current recovery of the electric portion, MGE requested deferral accounting for both the electric and natural gas operations. While deferral accounting for both electric and natural gas operations was an option, MGE maintained that current recovery would “smooth out” rate increases for customers.

MGE provided a further update of pension and retirement costs in Delayed Exhibit 12. The update in Delayed Exhibit 12 was based on actual results and conditions as of September 30, 2008, and October 31, 2008. Delayed Exhibit 12 showed that, based on pension asset valuation and discount rates as of September 30, 2008 and October 31, 2008, MGE estimated increased pension and retirement costs of $2,452,000 and $2,568,000 for the electric utility, respectively, and $1,379,000 and $1,445,000 for the natural gas utility, respectively.

The record does not justify inclusion of the estimated increased pension and post-retirement medical costs in the 2009 revenue requirement. In particular, there were questions with respect to MGE's funding obligations and the potential effects of the proposed amendment of the Federal Pension Protection Act of 2006. The losses experienced on MGE's pension assets meet the standards for deferral: they are a “once in a lifetime” event, material, and outside of the control of the utility. Accordingly, the Commission authorizes deferral accounting treatment, with carrying costs at the short-term debt rate, for the increased 2009 pension and post-retirement medical costs of both MGE's electric and natural gas utilities.

Comprehensive Workforce Planning Expenses

IBEW Local 2304 requested that the Commission include additional expenses in the revenue requirement sufficient to meet the comprehensive workforce planning challenges facing MGE. IBEW Local 2304 urges the Commission to recognize: (a) the need to hire ahead and authorize “above normal” staffing in this labor force transition period, (b) the need for the utility to be able to do its core utility work and staff accordingly to do that work (this can be accomplished, in most cases, without additional revenue), and (c) the need for the utility to engage the community through scholarships, career education, and recruitment programs. IBEW Local 2304 maintains that all of these are fundamental components of a comprehensive workforce plan and the necessary expenses should be included in the revenue requirement.

In the original record in this docket, MGE testified that the amount Commission staff proposed to include in rates for comprehensive workforce planning activities would be sufficient for 2008 and 2009. In this reopener, MGE asserted that if increased amounts were needed for this purpose in 2009, the company would have requested them.

The record does not conclusively indicate whether the Commission needs to increase MGE's revenue requirement to cover any increased costs of comprehensive workforce planning. Because it is MGE's position that sufficient amounts were included in revenue requirement in the base case to cover these costs, MGE should continue to report to the Commission with respect to its progress on this issue. MGE's management should also evaluate whether any cost savings resulting from replacing outside contractors with permanent employees could offset any increased comprehensive workplace planning costs.

Electric Revenue Allocation

The appropriate allocation for the type of costs originally included in this reopener, based on the cost-of-service used in the base case, is a combination of energy and coincident demand. MGE's revised and Commission staff's electric revenue allocations are similar. The differences between the proposals are small, with percentage increases generally varying by less than 0.3 percent per customer class if based on the same revenue requirement. Although MGE originally requested an increase in its electric revenue requirement, the final revenue requirement is a slight decrease. The Commission finds that a relatively uniform revenue allocation based on the Commission staff proposal is reasonable and that no rate class should receive an increase.

Electric Rate Design

MGE's current electric rates include the base rates authorized in the December 14, 2007, Commission *Final Decision* in docket 3270-UR-115 and the interim fuel surcharge authorized in the May 5, 2008, Commission order in docket 3270-FR-102. Both MGE's revised and Commission staff's rate design proposals included increasing the energy charges while maintaining the customer and demand charges at current levels. Because the revenue requirement has slightly decreased, lowering some of the energy charges and incorporating the fuel surcharge into the new base rates is appropriate. The Commission finds that the electric rate changes shown in Appendix B reasonably reflect the forecasted fuel and purchased power costs.

Order

1. This Final Decision shall be effective on January 1, 2009, when the rate increase becomes effective. MGE shall file the authorized rates with the Commission and place copies in all offices and pay stations prior to January 1, 2009.

2. MGE may substitute, for its existing rates for electric service, the rate changes contained in Appendix B. These changes shall be in effect until the issuance of an order by the Commission establishing new rates.

3. MGE shall prepare bill inserts that properly identify the rates authorized in this Final Decision. MGE shall distribute these inserts to customers with the first billing containing the rates authorized in this Final Decision and shall file copies of these inserts with the Commission before it distributes the inserts to customers.

4. The fuel costs in Appendix C shall be used for monthly monitoring of MGE's fuel costs, pursuant to Wis. Admin. Code ch. PSC 116.

5. MGE shall defer any refunds from ATC associated with its Network Service Fees until the refunds can be returned to ratepayers.

6. MGE shall defer any delay damages recovered under the ERGS facility lease, net of any external incremental costs, until the amount recovered can be returned to ratepayers.

7. MGE shall defer increased 2009 pension costs for both the natural gas and electric utilities.

8. In all other respects, the *Final Decision* issued in this docket on December 14, 2007, remains in effect without change.

9. Jurisdiction is retained.

Dated at Madison, Wisconsin, December 18, 2008

See attached Notice of Rights

PUBLIC SERVICE COMMISSION OF WISCONSIN 610 North Whitney Way P.O. Box 7854 Madison, Wisconsin 53707-7854

NOTICE OF RIGHTS FOR REHEARING OR JUDICIAL REVIEW, THE TIMES ALLOWED FOR EACH, AND THE IDENTIFICATION OF THE PARTY TO BE NAMED AS RESPONDENT

The following notice is served on you as part of the Commission's written decision. This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

PETITION FOR REHEARING

If this decision is an order following a contested case proceeding as defined in Wis. Stat. § 227.01(3), a person aggrieved by the decision has a right to petition the Commission for rehearing within 20 days of mailing of this decision, as provided in Wis.

Stat. § 227.49. The mailing date is shown on the first page. If there is no date on the first page, the date of mailing is shown immediately above the signature line. The petition for rehearing must be filed with the Public Service Commission of Wisconsin and served on the parties. An appeal of this decision may also be taken directly to circuit court through the filing of a petition for judicial review. It is not necessary to first petition for rehearing.

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. The petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of mailing of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of mailing of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission mailed its original decision. [1] The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

If this decision is an order denying rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not permitted.

Revised July 3, 2008

APPENDIX A

(CONTESTED)

In order to comply with Wis. Stat. § 227.47, the following parties who appeared before the agency are considered parties for purposes of review under Wis. Stat. § 227.53.

Public Service Commission of Wisconsin

(Not a party but must be served)

610 N. Whitney Way

P.O. Box 7854

Madison, WI 53707-7854

MADISON GAS AND ELECTRIC COMPANY

Richard K. Nordeng

Stafford Rosenbaum LLP

PO Box 1784

Madison, WI 53701-1784

CITIZENS UTILITY BOARD

Curt F. Pawlisch

Kira E. Loehr

Cullen Weston Pines & Bach LLP

122 West Washington Avenue, Suite 900

Madison, WI 53703

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS LOCAL UNION NO. 2304

David Poklinkoski

1602 South Park Street, Room 101

Madison, WI 53715

RENEW WISCONSIN

Michael Vickerman

222 South Hamilton Street

Madison, WI 53703

WISCONSIN END-USER GAS AND ELECTRIC ASSOCIATION

Darcy Fabrizius

PO Box 2226

Waukesha, WI 53187-2226

WISCONSIN INDUSTRIAL ENERGY GROUP

Steven A. Heinzen

Rea L. Holmes

Godfrey & Kahn, S.C.

1 East Main Street, Suite 500

Madison, WI 53703

Appendix B

MADISON GAS AND ELECTRIC COMPANY ESTIMATED RETAIL ELECTRIC REVENUE FOR THE TEST YEAR ENDING DEC. 31, 2009

	RATE CLASS	kWh SALES	PRESENT REVENUES [1]	PROPOSED REVENUES	DOLLAR CHANGE	PERCENT CHANGE
Rg-1	Residential	843,448,871	$ 121,924,790	$ 120,743,962	$ (1,180,828)	-0.97%
Rg-2	Residential Time-of-Use	10,124,196	$ 1,250,546	$ 1,239,842	$ (10,704)	-0.86%
Rw-1	Residential Controlled Water Heating	124,595	$ 12,192	$ 12,118	$ (74)	-0.61%
Rg-3	Residential Lifeline (Closed)	151,107	$ 17,964	$ 17,785	$ (179)	-1.00%
	TOTAL RESIDENTIAL	853,848,769	$ 123,205,492	$ 122,013,707	$ (1,191,786)	**-0.97%**
Cg-5	Small C&I Lighting and Power (<20 kW)	218,553,660	$ 29,749,678	$ 29,443,703	$ (305,975)	-1.03%
Cg-3	Small C&I Optional Time-of-use (<20 kW)	5,911,630	$ 717,127	$ 711,059	$ (6,068)	-0.85%
Cg-1A	C&I Lighting and Power (20-75 kW)	293,666,846	$ 33,886,847	$ 33,635,850	$ (250,997)	-0.74%
Cg-1B	C&I Lighting and Power (76-200 kW)	316,759,214	$ 34,303,825	$ 34,033,186	$ (270,639)	-0.79%
Cg-4A	C&I Optional Time-of-Use (20-75 kW)	11,433,836	$ 1,118,340	$ 1,110,579	$ (7,761)	-0.69%
Cg-4B	C&I Optional Time-of-Use (76-200kW)	24,615,250	$ 2,427,886	$ 2,411,177	$ (16,710)	-0.69%
	TOTAL SMALL BUSINESS	870,940,436	$ 102,203,703	$ 101,345,554	$ (858,150)	**-0.84%**
Cg-2	C&I Lighting and Power Time-of-Use (>200 kW)	866,664,321	$ 79,485,673	$ 79,009,655	$ (476,018)	-0.60%

Cg-6	C&I Lighting and Power Large Annual HLF (>1 MW)	196,280,809	$ 15,234,759	$ 15,192,608	$ (42,152)	-0.28%
Cp-1	C&I HLF Direct Control Interruptible - Trans. Volt.	98,471,698	$ 4,531,774	$ 4,531,458	$ (317)	-0.01%
	TOTAL LARGE BUSINESS	1,161,416,828	$ 99,252,206	$ 98,733,720	$ (518,486)	**-0.52%**
Sp-3	University of Wisconsin Time-of-Use	386,557,847	$ 29,984,910	$ 29,899,067	$ (85,843)	-0.29%
Sp-4	Oscar Mayer Foods Corporation Time-of-Use	73,739,585	$ 5,653,307	$ 5,638,288	$ (15,018)	-0.27%
Sp-5	Capitol Heat, Light, and Power Time-of-Use	1,525,000	$ 244,754	$ 242,665	$ (2,089)	-0.85%
	TOTAL CONTRACT SERVICES	461,822,432	$ 35,882,971	$ 35,780,021	$ (102,950)	**-0.29%**
Gf-1	General Flat Rate	4,113,277	$ 461,031	$ 457,427	$ (3,603)	-0.78%
Mg-2	Secondary Service for Municipal Defense Sirens	0	$ 3,452	$ 3,423	$ (29)	-0.84%
MLS	Athletic Field Lighting	496,352	$ 61,290	$ 60,833	$ (457)	-0.75%
OL-1	Outdoor Overhead Lighting - Private Unmetered	1,754,328	$ 456,416	$ 452,135	$ (4,281)	-0.94%
	TOTAL MISCELLANEOUS AND LIGHTING	6,363,957	$ 982,188	$ 973,818	$ (8,370)	**-0.85%**
SL-1	St. Lighting - Company-Owned & Maintained	826,366	$ 203,098	$ 201,508	$ (1,590)	-0.78%
SL-2	St. Lighting - Cust.-Owned & Cust.-Maintained	4,474,811	$ 461,486	$ 458,847	$ (2,639)	-0.57%

SL-3	St. Lighting - Cust.-Owned & Company-Maintained	4,468,526	$ 664,924	$ 660,451	$ (4,472)	-0.67%
	TOTAL STREET LIGHTING SERVICE	9,769,703	$ 1,329,508	$ 1,320,806	$ (8,701)	**-0.65%**
BGS	Backup Generation Service	Included	$ 592,496	$ 592,496	$ -	0.00%
RWE-1	Residential Wind Energy Program	in the #s	$ 317,650	$ 317,650	$ -	0.00%
BWE-1	Business Wind Energy Program	above	$ 86,570	$ 86,570	$ -	0.00%
TOTAL RETAIL ELECTRIC SALES REVENUE		3,364,162,125	$ 363,852,785	$ 361,164,342	$ (2,688,443)	**-0.74%**
	Interdepartmental	5,880,116	$ 589,298	$ 584,912	$ (4,387)	-0.74%
TOTAL RETAIL ELEC. SALES REVENUE w/ INTERD.		3,370,042,241	$ 364,442,083	$ 361,749,254	**$ (2,692,829)**	**-0.74%**

MADISON GAS AND ELECTRIC COMPANY PRESENT & AUTHORIZED RATES

TYPE OF SERVICE		Monthly Equivalent	PRESENT RATES (Includes Fuel Surcharge)		AUTHORIZED RATES		Monthly Equivalent
RESIDENTIAL SERVICE Rg-1							
Customer Charge		$8.70	$0.28590	per bill per day	$0.28590	per bill per day	$8.70
Distribution Charge			$0.03100	per kWh	$0.03100	per kWh	
Electricity Charges:	Winter		$0.09485	per kWh	$0.09345	per kWh	
	Summer		$0.10535	per kWh	$0.10395	per kWh	
RESIDENTIAL TIME OF USE Rg-2							
Customer Charge		$8.70	$0.28590	per bill per day	$0.28590	per bill per day	$8.70
Distribution Charge			$0.03100	per kWh	$0.03100	per kWh	
Electricity Charges							

On-Peak	Winter		$0.18249 per kWh		$0.18040 per kWh	
Off-Peak	Winter		$0.03599 per kWh		$0.03545 per kWh	
On-Peak	Summer		$0.20739 per kWh		$0.20530 per kWh	
Off-Peak	Summer		$0.03599 per kWh		$0.03545 per kWh	
RESIDENTIAL CONTROLLED WATER HEATING Rw-1						
Customer Charge		$3.40	$0.11190 per bill per day		$0.11190 per bill per day	$3.40
Distribution Charge			$0.03100 per kWh		$0.03100 per kWh	
Electricity Charges:	Winter		$0.04570 per kWh		$0.04510 per kWh	
	Summer		$0.05209 per kWh		$0.05150 per kWh	
RESIDENTIAL LIFELINE Rg-3						
Customer Charge		$4.80	$0.15780 per bill per day		$0.15780 per bill per day	$4.80
Distribution Charge			$0.03100 per kWh		$0.03100 per kWh	
Electricity Charges						
First 300 kWh per month	Winter		$0.06028 per kWh		$0.05923 per kWh	
Over 300 kWh per month	Winter		$0.09485 per kWh		$0.09345 per kWh	
First 300 kWh per month	Summer		$0.06784 per kWh		$0.06684 per kWh	
Over 300 kWh per month	Summer		$0.10535 per kWh		$0.10395 per kWh	
SMALL C/I LIGHTING AND POWER Cg-5 (0-20 kW)						
Customer Charge		$8.70	$0.28590 per bill per day		$0.28590 per bill per day	$8.70
Distribution Charge			$0.03100 per kWh		$0.03100 per kWh	
Electricity Charges:	Winter		$0.09485 per kWh		$0.09345 per kWh	
	Summer		$0.10535 per kWh		$0.10395 per kWh	
SMALL C/I OPTIONAL TIME OF USE Cg-3 (<20 kW)						
Customer Charge						
Single Phase		$8.70	$0.28590 per bill per day		$0.28590 per bill per day	$8.70
Three Phase			$0.61480 per bill per day		$0.61480 per bill per day	
Distribution Charge			$0.03100 per kWh		$0.03100 per kWh	

Electricity Charges							
On-Peak	Winter		$0.18249	per kWh	$0.18040	per kWh	
Off-Peak	Winter		$0.03599	per kWh	$0.03545	per kWh	
On-Peak	Summer		$0.20739	per kWh	$0.20530	per kWh	
Off-Peak	Summer		$0.03599	per kWh	$0.03545	per kWh	

C/I LIGHTING AND POWER SERVICE Cg-1 LEVEL A (20-75 kW)

Customer Charge		$35.50	$1.16720	per bill per day	$1.16720	per bill per day	$35.50
Distribution Charge							
Customer Maximum Demand		$3.80	$0.12493	per kW per day	$0.12493	per kW per day	$3.80
Max. Monthly Demand:	Winter	$6.95	$0.22850	per kW per day	$0.22850	per kW per day	$6.95
	Summer	$8.50	$0.27960	per kW per day	$0.27960	per kW per day	$8.50
Non-Capped Energy:	Winter		$0.06709	per kWh	$0.06625	per kWh	
	Summer		$0.07773	per kWh	$0.07685	per kWh	
Act 141 $ in Non-Lg.Cust. Rates			$0.00163		$0.00163	per kWh	
Capped Energy:	Winter		$0.06551	per kWh	$0.06467	per kWh	
	Summer		$0.07615	per kWh	$0.07527	per kWh	
Act 141 $ in Lg.Cust. Rates			$0.00005		$0.00005	per kWh	

C/I LIGHTING AND POWER SERVICE Cg-1 LEVEL B (76-200 kW)

Customer Charge		$35.50	$1.1672	per bill per day	$1.16720	per bill per day	$35.50
Distribution Charge							
Customer Maximum Demand		$3.80	$0.12493	per kW per day	$0.12493	per kW per day	$3.80
Electricity Charges							
Max. Monthly Demand:	Winter	$6.95	$0.22850	per kW per day	$0.22850	per kW per day	$6.95
	Summer	$8.50	$0.27960	per kW per day	$0.27960	per kW per day	$8.50
Non-Capped Energy:	Winter		$0.06709	per kWh	$0.06625	per kWh	
	Summer		$0.07773	per kWh	$0.07685	per kWh	
Act 141 $ in Non-Lg.Cust. Rates			$0.00163		$0.00163	per kWh	
Capped Energy:	Winter		$0.06551	per kWh	$0.06467	per kWh	
	Summer		$0.07615	per kWh	$0.07527	per kWh	

Act 141 $ in Lg.Cust. Rates			$0.00005		$0.00005	per kWh	

C/I LIGHTING AND POWER TIME-OF-USE SERVICE Cg-4 LEVEL A (20-75 kW)

Customer Charge							
Single Phase		$40.00	$1.31520	per bill per day	$1.31520	per bill per day	$40.00
Three Phase		$51.70	$1.69960	per bill per day	$1.69960	per bill per day	$51.70
Distribution Charge							
Customer Maximum Demand		$3.80	$0.12493	per kW per day	$0.12493	per kW per day	$3.80
Electricity Charges							
Max. Monthly Demand:	Winter	$6.95	$0.22850	per kW per day	$0.22850	per kW per day	$6.95
	Summer	$8.50	$0.27960	per kW per day	$0.27960	per kW per day	$8.50
Non-Capped On-Pk Energy:	Winter		$0.10003	per kWh	$0.09935	per kWh	
	Summer		$0.11042	per kWh	$0.10975	per kWh	
Non-Capped Off-Pk Energy:	Winter		$0.04838	per kWh	$0.04770	per kWh	
	Summer		$0.04838	per kWh	$0.04770	per kWh	
Act 141 $ in Non-Lg.Cust. Rates			$0.00163		$0.00163	per kWh	
Capped On-Pk.Energy:	Winter		$0.09845	per kWh	$0.09777	per kWh	
	Summer		$0.10884	per kWh	$0.10817	per kWh	
Capped Off-Pk.Energy:	Winter		$0.04680	per kWh	$0.04612	per kWh	
	Summer		$0.04680	per kWh	$0.04612	per kWh	
Act 141 $ in Lg.Cust. Rates			$0.00005		$0.00005	per kWh	

C/I LIGHTING AND POWER TIME-OF-USE SERVICE Cg-4 LEVEL B (76-200 kW)

Customer Charge							
Single Phase		$40.00	$1.31520	per bill per day	$1.31520	per bill per day	$40.00
Three Phase		$51.70	$1.69960	per bill per day	$1.69960	per bill per day	$51.70
Distribution Charge							
Customer Maximum Demand		$3.80	$0.12493	per kW per day	$0.12493	per kW per day	$3.80
Electricity Charges							
Max. Monthly Demand:	Winter	$6.95	$0.22850	per kW per day	$0.22850	per kW per day	$6.95
	Summer	$8.50	$0.27960	per kW per day	$0.27960	per kW per day	$8.50

Non-Capped On-Pk Energy:	Winter		$0.10003 per kWh		$0.09935 per kWh	
	Summer		$0.11042 per kWh		$0.10975 per kWh	
Non-Capped Off-Pk Energy:	Winter		$0.04838 per kWh		$0.04770 per kWh	
	Summer		$0.04838 per kWh		$0.04770 per kWh	
Act 141 $ in Non-Lg.Cust. Rates			$0.00163		$0.00163 per kWh	
Capped On-Pk.Energy:	Winter		$0.09845 per kWh		$0.09777 per kWh	
	Summer		$0.10884 per kWh		$0.10817 per kWh	
Capped Off-Pk.Energy:	Winter		$0.04680 per kWh		$0.04612 per kWh	
	Summer		$0.04680 per kWh		$0.04612 per kWh	
Act 141 $ in Lg.Cust. Rates			$0.00005		$0.00005 per kWh	

C/I LIGHTING AND POWER SERVICE TIME-OF-USE CG-2 (OVER 200 kW)

Customer Charge		$159.00	$5.22740	per bill per day	$5.22740 per bill per day	$159.00
Distribution Charges						
Customer Maximum Demand		$4.55	$0.14959	per kW per day	$0.14959 per kW per day	$4.55
Electricity Charges						
Max. Monthly Demand:	Winter	$6.95	$0.22850	per kW per day	$0.22850 per kW per day	$6.95
	Summer	$8.50	$0.27960	per kW per day	$0.27960 per kW per day	$8.50
Non-Capped On-Pk Energy:	Winter		$0.07941	per kWh	$0.07890 per kWh	
	Summer		$0.08773	per kWh	$0.08720 per kWh	
Non-Capped Off-Pk Energy:	Winter		$0.04766	per kWh	$0.04709 per kWh	
	Summer		$0.04766	per kWh	$0.04709 per kWh	
Act 141 $ in Non-Lg.Cust. Rates			$0.00163		$0.00163 per kWh	
Capped On-Pk.Energy:	Winter		$0.07780	per kWh	$0.07729 per kWh	
	Summer		$0.08612	per kWh	$0.08559 per kWh	
Capped Off-Pk.Energy:	Winter		$0.04605	per kWh	$0.04548 per kWh	
	Summer		$0.04605	per kWh	$0.04548 per kWh	
Act 141 $ in Lg.Cust. Rates			$0.00002		$0.00002 per kWh	

C/I LIGHTING AND POWER SERVICE TIME-OF-USE HLF CG-6 (OVER 1000 kW)

Customer Charge	$159.00	$5.2274	per bill per day	$5.22740 per bill per day	$159.00

Distrib. Charges	Cust. Max. kW	$4.65	$0.15288	per kW per day	$0.15288	per kW per day	$4.65
Electricity Charges							
Max. Monthly Demand:	Winter	$6.95	$0.22850	per kW per day	$0.22850	per kW per day	$6.95
	Summer	$8.50	$0.27960	per kW per day	$0.27960	per kW per day	$8.50
Non-Capped On-Pk Energy:	Winter		$0.07237	per kWh	$0.07215	per kWh	
	Summer		$0.07968	per kWh	$0.07945	per kWh	
Non-Capped Off-Pk Energy:	Winter		$0.04736	per kWh	$0.04715	per kWh	
	Summer		$0.04736	per kWh	$0.04715	per kWh	
Act 141 $ in Non-Lg.Cust. Rates			$0.00163		$0.00163	per kWh	
Capped On-Pk.Energy:	Winter		$0.07076	per kWh	$0.07054	per kWh	
	Summer		$0.07807	per kWh	$0.07784	per kWh	
Capped Off-Pk.Energy:	Winter		$0.04575	per kWh	$0.04554	per kWh	
	Summer		$0.04575	per kWh	$0.04554	per kWh	
Act 141 $ in Lg.Cust. Rates			$0.00002		$0.00002	per kWh	
C/I HIGH LOAD FACTOR DIRECT CONTROL INTERRUPTIBLE SERVICE TRANS. VOLTAGE Cp-1							
Customer Charge		$650.00	$21.37000	per bill per day	$21.37000	per bill per day	$650.00
Distribution Charges			None		None		
Electricity Charges							
Max. Monthly Demand:	Winter	$2.20	$0.07233	per kW per day	$0.07233	per kW per day	$2.20
	Summer	$2.75	$0.09041	per kW per day	$0.09041	per kW per day	$2.75
On-Peak Energy	Winter		$0.05101	per kWh	$0.05100	per kWh	
	Summer		$0.06111	per kWh	$0.06110	per kWh	
Off-peak Energy	Winter		$0.03543	per kWh	$0.03543	per kWh	
	Summer		$0.03543	per kWh	$0.03543	per kWh	
Act 141 $ in Base Rates			$0.00001		$0.00001	per kWh	
UNIVERSITY OF WISCONSIN TIME-OF-USE SP-3							
Customer Charge		$6,360.00	$209.0958	per bill per day	$209.0958	per bill per day	$6,360.00
Distrib. Charges Cust.Max.kW		$3.30	$0.10849	per kW per day	$0.10849	per kW per day	$3.30
Electricity Charges							

Max. Monthly Demand:	Winter	$6.95	$0.22850	per kW per day	$0.22850	per kW per day	$6.95
	Summer	$8.50	$0.27960	per kW per day	$0.27960	per kW per day	$8.50
On-Peak Energy	Winter		$0.07286	per kWh	$0.07262	per kWh	
	Summer		$0.07817	per kWh	$0.07792	per kWh	
Off-peak Energy	Winter		$0.04833	per kWh	$0.04812	per kWh	
	Summer		$0.04833	per kWh	$0.04812	per kWh	
Act 141 $ in Base Rates			$0.00002		$0.00002	per kWh	
OSCAR MAYER TIME-OF-USE SP-4							
Customer Charge		$239.00	$7.85760	per day per bill	$7.85760	per day per bill	$239.00
Distribution Charges							
Customer Maximum Demand		$3.35	$0.11020	per kW per day	$0.11020	per kW per day	$3.35
Electricity Charges							
Firm Contract Demand	Winter	$6.95	$0.22850	per kW per day	$0.22850	per kW per day	$6.95
	Summer	$8.50	$0.27960	per kW per day	$0.27960	per kW per day	$8.50
On-Peak Energy	Winter		$0.07103	per kWh	$0.07082	per kWh	
	Summer		$0.07733	per kWh	$0.07712	per kWh	
Off-peak Energy	Winter		$0.04577	per kWh	$0.04557	per kWh	
	Summer		$0.04577	per kWh	$0.04557	per kWh	
Supplemental Energy	Winter		$0.07103	per kWh	$0.07082	per kWh	
	Summer		$0.07733	per kWh	$0.07712	per kWh	
Act 141 $ in Base Rates			$0.00002		$0.00002	per kWh	
CAPITOL HEATING TIME-OF-USE SP5							
Customer Charge		$652.00	$21.43570	per day per bill	$21.43570	per day per bill	$652.00
Distribution Charges							
Customer Maximum Demand		$3.30	$0.10840	per kW per day	$0.10840	per kW per day	$3.30
Electricity Charges							
Max. Monthly Demand:	Winter	$8.15	$0.26780	per kW per day	$0.26780	per kW per day	$8.15
	Summer	$9.75	$0.32040	per kW per day	$0.32040	per kW per day	$9.75

Non-Capped On-Pk Energy:	Winter		$0.07678	per kWh	$0.07540	per kWh	
	Summer		$0.08118	per kWh	$0.07980	per kWh	
Non-Capped Off-Pk Energy:	Winter		$0.04736	per kWh	$0.04600	per kWh	
	Summer		$0.04736	per kWh	$0.04600	per kWh	
Act 141 $ in Non-Lg.Cust. Rates			$0.00163		$0.00163		
Capped On-Pk.Energy:	Winter		$0.07515	per kWh	$0.07377	per kWh	
	Summer		$0.07955	per kWh	$0.07817	per kWh	
Capped Off-Pk.Energy:	Winter		$0.04573	per kWh	$0.04437	per kWh	
	Summer		$0.04573	per kWh	$0.04437	per kWh	
Act 141 $ in Lg.Cust. Rates			$0.00000		$0.00000	per kWh	
SUMMER CURTAILABLE SERVICE (SCS)							
Cg-1 Summer Interruptible kW		($6.00)	($0.19726)	per kW per day	($0.19726)	per kW per day	($6.00)
Cg-4 Summer Interruptible kW		($6.00)	($0.19726)	per kW per day	($0.19726)	per kW per day	($6.00)
Cg-2 Summer Interruptible kW		($6.00)	($0.19726)	per kW per day	($0.19726)	per kW per day	($6.00)
Cg-6 Summer Interruptible kW		($6.00)	($0.19726)	per kW per day	($0.19726)	per kW per day	($6.00)
Sp-3 Summer Interruptible kW		($6.00)	($0.19726)	per kW per day	($0.19726)	per kW per day	($6.00)
INTERRUPTIBLE SERVICE RIDER Is-1							
Variable Pricing							
Cg-2 Interruptible kW		($3.75)	($0.12329)	per kW per day	($0.12329)	per kW per day	($3.75)
Cg-6 Interruptible kW		($3.75)	($0.12329)	per kW per day	($0.12329)	per kW per day	($3.75)
Sp-3 Interruptible kW		($3.75)	($0.12329)	per kW per day	($0.12329)	per kW per day	($3.75)
Fixed Pricing							
Cg-2 Interruptible kW		($3.00)	($0.09863)	per kW per day	($0.09863)	per kW per day	($3.00)
Cg-6 Interruptible kW		($3.00)	($0.09863)	per kW per day	($0.09863)	per kW per day	($3.00)

Sp-3 Interruptible kW	($3.00)	($0.09863)	per kW per day	($0.09863)	per kW per day	($3.00)
DIRECT CONTROL INTERRUPTIBLE SERVICE RIDER Is-2						
Variable Pricing						
Cg-1 Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
Cg-4 Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
Cg-2 Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
Cg-6 Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
Sp-3 Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
Fixed Pricing						
Cg-1 Interruptible kW	($3.25)	($0.10685)	per kW per day	($0.10685)	per kW per day	($3.25)
Cg-4 Interruptible kW	($3.25)	($0.10685)	per kW per day	($0.10685)	per kW per day	($3.25)
Cg-2 Interruptible kW	($3.25)	($0.10685)	per kW per day	($0.10685)	per kW per day	($3.25)
Cg-6 Interruptible kW	($3.25)	($0.10685)	per kW per day	($0.10685)	per kW per day	($3.25)
Sp-3 Interruptible kW	($3.25)	($0.10685)	per kW per day	($0.10685)	per kW per day	($3.25)

MISCELLANEOUS FLAT RATE SERVICE GF-1						
LEVEL I Telephone Booths		$6.43	per bill per unit	$6.38	per bill per unit	
LEVEL II CATV Amplifiers		$64.67	per bill per unit	$64.13	per bill per unit	
LEVEL III Unmetered Service						
Customer Charge	$8.70	$0.28590	per day per bill	$0.28590	per day per bill	$8.70
Distribution Service		$0.03100	per kWh	$0.03100	per kWh	
Electricity Service		$0.07619	per kWh	$0.07530	per kWh	
SECONDARY SERVICE FOR MUNICIPAL DEFENSE SIRENS Mg-2						

Motor-Driven Sirens		$3.44	per bill per unit	$3.41	per bill per unit	
Electronic Sirens		$4.99	per bill per unit	$4.95	per bill per unit	
ATHLETIC FIELD LIGHTING MLS						
Customer Charge	$8.70	$0.28590	per day per bill	$0.28590	per day per bill	$8.70
Distribution Charge		$0.03100	per kWh	$0.03100	per kWh	
Electric Charge		$0.08772	per kWh	$0.08680	per kWh	

OUTDOOR OVERHEAD LIGHTING SERVICE -- OL-1 (PRIVATE UNMETERED)

DUSK-TO-DAWN YARD LIGHTING				
70 WATT HPS LAMPS	$10.98	per lamp per bill	$10.85	per lamp per bill
100 WATT HPS LAMPS	$11.82	per lamp per bill	$11.68	per lamp per bill
150 WATT HPS LAMPS	$13.19	per lamp per bill	$13.03	per lamp per bill
175 WATT MV LAMPS	$13.79	per lamp per bill	$13.62	per lamp per bill
250 WATT MV LAMPS	$15.88	per lamp per bill	$15.69	per lamp per bill
400 WATT MV LAMPS	$19.54	per lamp per bill	$19.31	per lamp per bill
SECURITY FLOOD LIGHTING				
70 WATT HPS LAMPS	$12.20	per lamp per bill	$12.05	per lamp per bill
150 WATT HPS LAMPS	$15.10	per lamp per bill	$14.92	per lamp per bill
250 WATT HPS LAMPS	$18.62	per lamp per bill	$18.40	per lamp per bill
400 WATT HPS LAMPS	$22.57	per lamp per bill	$22.30	per lamp per bill
70 WATT MH LAMPS	$12.20	per lamp per bill	$12.05	per lamp per bill
150 WATT MH LAMPS	$15.10	per lamp per bill	$14.92	per lamp per bill
250 WATT MH LAMPS	$18.62	per lamp per bill	$18.40	per lamp per bill
400 WATT MH LAMPS	$22.57	per lamp per bill	$22.30	per lamp per bill
POLES Wood	$7.00	per pole per bill	$7.00	per pole per bill
Non-Wood	$13.00	per pole per bill	$13.00	per pole per bill

STREET LIGHTING SERVICE -- SL-1 (COMPANY OWNED AND COMPANY MAINTAINED)

Distribution Service Charge	$2.85	per lamp per bill	$2.85	per lamp per bill

Electricity Service Unit Charge	$0.05953 per kWh	$0.05890 per kWh
OVERHEAD SERVICE (Facilities Charges)		
175 WATT MV	$6.40 per lamp per bill	$6.34 per lamp per bill
250 WATT MV	$6.50 per lamp per bill	$6.44 per lamp per bill
400 WATT MV	$8.40 per lamp per bill	$8.32 per lamp per bill
70 WATT HPS	$4.70 per lamp per bill	$4.65 per lamp per bill
100 WATT HPS	$4.80 per lamp per bill	$4.75 per lamp per bill
150 WATT HPS	$5.40 per lamp per bill	$5.35 per lamp per bill
200 WATT HPS	$6.30 per lamp per bill	$6.24 per lamp per bill
250 WATT HPS	$7.00 per lamp per bill	$6.93 per lamp per bill
300 WATT INC	$7.00 per lamp per bill	$6.93 per lamp per bill
MIDNIGHT		
400 WATT MV MN	$8.40 per lamp per bill	$8.32 per lamp per bill
UNDERGROUND SERVICE (Facilities Charges)		
70 WATT HPS ANEN	$15.10 per lamp per bill	$14.95 per lamp per bill
100 WATT HPS ANEN	$15.20 per lamp per bill	$15.05 per lamp per bill
150 WATT HPS ANEN	$15.40 per lamp per bill	$15.25 per lamp per bill
200 WATT HPS ANEN	$15.60 per lamp per bill	$15.44 per lamp per bill
250 WATT HPS ANEN	$16.30 per lamp per bill	$16.14 per lamp per bill

STREET LIGHTING SERVICE -- SL-2 (CUSTOMER OWNED AND CUSTOMER MAINTAINED)

Distribution Service Charge	$2.85	per lamp per bill	$2.85	per lamp per bill
Electricity Service Unit Charge	$0.05953	per kWh	$0.05890	per kWh

Note: Below are the monthly SL-2 charges/lamp resulting from the Distribution Service & Electricity Service Charges, above)

ALL NIGHT				
100-WATT MV ANEN	$5.17	per lamp per bill	$5.15	per lamp per bill
175-WATT MV ANEN	$6.90	per lamp per bill	$6.86	per lamp per bill

250-WATT MV ANEN	$8.51	per lamp per bill	$8.45	per lamp per bill
400-WATT MV ANEN	$11.92	per lamp per bill	$11.80	per lamp per bill
70-WATT HPS ANEN	$4.52	per lamp per bill	$4.50	per lamp per bill
100-WATT HPS ANEN	$5.17	per lamp per bill	$5.15	per lamp per bill
150-WATT HPS ANEN	$6.24	per lamp per bill	$6.21	per lamp per bill
200-WATT HPS ANEN	$7.31	per lamp per bill	$7.27	per lamp per bill
250-WATT HPS ANEN	$8.51	per lamp per bill	$8.45	per lamp per bill
400-WATT HPS ANEN	$11.60	per lamp per bill	$11.51	per lamp per bill
35-WATT LPS ANEN	$3.68	per lamp per bill	$3.67	per lamp per bill
55-WATT LPS ANEN	$4.10	per lamp per bill	$4.09	per lamp per bill
90-WATT LPS ANEN	$4.93	per lamp per bill	$4.91	per lamp per bill
50-WATT MH ANEN	$4.10	per lamp per bill	$4.09	per lamp per bill
70-WATT MH ANEN	$4.52	per lamp per bill	$4.50	per lamp per bill
100-WATT MH ANEN	$5.17	per lamp per bill	$5.15	per lamp per bill
175-WATT MH ANEN	$6.84	per lamp per bill	$6.80	per lamp per bill
MIDNIGHT SCHEDULE				
250-WATT MV MN	$5.71	per lamp per bill	$5.68	per lamp per bill
400-WATT MV MN	$7.37	per lamp per bill	$7.33	per lamp per bill
70-WATT HPS MN	$3.68	per lamp per bill	$3.67	per lamp per bill
100-WATT HPS MN	$4.04	per lamp per bill	$4.03	per lamp per bill
150-WATT HPS MN	$4.58	per lamp per bill	$4.56	per lamp per bill
200-WATT HPS MN	$5.11	per lamp per bill	$5.09	per lamp per bill
250-WATT HPS MN	$5.71	per lamp per bill	$5.68	per lamp per bill
400-WATT HPS MN	$7.20	per lamp per bill	$7.15	per lamp per bill
35-WATT LPS MN	$3.21	per lamp per bill	$3.26	per lamp per bill
55-WATT LPS MN	$3.50	per lamp per bill	$3.50	per lamp per bill
90-WATT LPS MN	$3.92	per lamp per bill	$3.91	per lamp per bill
50-WATT MH MN	$3.45	per lamp per bill	$3.44	per lamp per bill
70-WATT MH MN	$3.68	per lamp per bill	$3.67	per lamp per bill

100-WATT MH MN	$4.04	per lamp per bill	$4.03	per lamp per bill
175-WATT MH MN	$4.81	per lamp per bill	$4.79	per lamp per bill

STREET LIGHTING SERVICE -- SL-2 (CUSTOMER OWNED & MAINTAINED) (Continued)

10:30 P.M. SCHEDULE				
400-WATT MV 10:30	$6.12	per lamp per bill	$6.09	per lamp per bill
70-WATT HPS 10:30	$3.45	per lamp per bill	$3.44	per lamp per bill
100-WATT HPS 10:30	$3.68	per lamp per bill	$3.67	per lamp per bill
150-WATT HPS 10:30	$4.10	per lamp per bill	$4.09	per lamp per bill
200-WATT HPS 10:30	$4.46	per lamp per bill	$4.44	per lamp per bill
250-WATT HPS 10:30	$4.87	per lamp per bill	$4.85	per lamp per bill
400-WATT HPS 10:30	$6.01	per lamp per bill	$5.97	per lamp per bill
3:00 A.M. SCHEDULE				
100-WATT MV 3AM	$4.58	per lamp per bill	$4.56	per lamp per bill
70-WATT HPS 3AM	$4.10	per lamp per bill	$4.09	per lamp per bill
100-WATT HPS 3AM	$4.58	per lamp per bill	$4.56	per lamp per bill
150-WATT HPS 3AM	$5.41	per lamp per bill	$5.38	per lamp per bill
200-WATT HPS 3AM	$6.24	per lamp per bill	$6.21	per lamp per bill
250-WATT HPS 3AM	$7.08	per lamp per bill	$7.03	per lamp per bill
400-WATT HPS 3AM	$9.40	per lamp per bill	$9.33	per lamp per bill
70-WATT MH 3AM	$4.10	per lamp per bill	$4.09	per lamp per bill
100-WATT MH 3AM	$4.58	per lamp per bill	$4.56	per lamp per bill
175-WATT MH 3AM	$5.83	per lamp per bill	$5.80	per lamp per bill

STREET LIGHTING SERVICE -- SL-3 (CUSTOMER OWNED AND COMPANY MAINTAINED)

Distribution Service Charge	$2.85	per lamp per bill	$2.85	per lamp per bill
Electricity Service Unit Charge	$0.05953	per kWh	$0.05890	per kWh

OVERHEAD SERVICE (Maintenance Charges)

ALL NIGHT SCHEDULE

70 WATT HPS ANEN	$1.10	per lamp per bill	$1.08	per lamp per bill
100 WATT HPS ANEN	$1.10	per lamp per bill	$1.08	per lamp per bill
150 WATT HPS ANEN	$1.10	per lamp per bill	$1.08	per lamp per bill
200 WATT HPS ANEN	$1.50	per lamp per bill	$1.48	per lamp per bill
250 WATT HPS ANEN	$1.50	per lamp per bill	$1.48	per lamp per bill
OVERHEAD SERVICE (Maintenance Charges)				
MIDNIGHT SCHEDULE				
70 WATT HPS MN	$1.10	per lamp per bill	$1.08	per lamp per bill
100 WATT HPS MN	$1.10	per lamp per bill	$1.08	per lamp per bill
150 WATT HPS MN	$1.10	per lamp per bill	$1.08	per lamp per bill
200 WATT HPS MN	$1.20	per lamp per bill	$1.20	per lamp per bill
250 WATT HPS MN	$1.50	per lamp per bill	$1.48	per lamp per bill
UNDERGROUND SERVICE (Maintenance Charges)				
ALL NIGHT SCHEDULE				
175 WATT MV ANEN	$1.10	per lamp per bill	$1.08	per lamp per bill
250 WATT MV ANEN	$1.50	per lamp per bill	$1.48	per lamp per bill
70 WATT HPS ANEN	$1.10	per lamp per bill	$1.08	per lamp per bill
100 WATT HPS ANEN	$1.10	per lamp per bill	$1.08	per lamp per bill
150 WATT HPS ANEN	$1.10	per lamp per bill	$1.08	per lamp per bill
200 WATT HPS ANEN	$1.50	per lamp per bill	$1.48	per lamp per bill
250 WATT HPS ANEN	$1.50	per lamp per bill	$1.48	per lamp per bill
MIDNIGHT SCHEDULE				
100 WATT HPS MN	$1.10	per lamp per bill	$1.08	per lamp per bill
150 WATT HPS MN	$1.10	per lamp per bill	$1.08	per lamp per bill
250 WATT HPS MN	$1.50	per lamp per bill	$1.48	per lamp per bill

BACKUP GENERATION SERVICE (BGS)						
Diesel Generators	$1.50	$0.04932	per kW per day	$0.04932	per kW per day	$1.50
Diesel Generators - New Contract	$2.00	$0.06575	per kW per day	$0.06575	per kW per day	$2.00
Natural Gas Generators	$3.50	$0.11507	per kW per day	$0.11507	per kW per day	$3.50
Natural Gas Generators - New	$4.00	$0.13151	per kW per day	$0.13151	per kW per day	$4.00
RESIDENTIAL WIND ENERGY (RWE-1)						
Incremental Charge for Wind Energy		$0.01000	per kWh	$0.01000	per kWh	
BUSINESS WIND ENERGY (BWE-1)						
Incremental Charge for Wind Energy		$0.01000	per kWh	$0.01000	per kWh	
PARALLEL GENERATION (Pg-1)						
Customer Charge						
Single Phase	$7.00	$0.23010	per bill per day	$0.23010	per bill per day	$7.00
Three Phase	$8.30	$0.27290	per bill per day	$0.27290	per bill per day	$8.30
ENERGY PAYMENTS TO CUSTOMER:						
Electric Charge						
Primary Service, On-Peak		$0.06252	per kWh	$0.06252	per kWh	
Primary Service, Off-Peak		$0.04376	per kWh	$0.04376	per kWh	
Secondary Service, On-Peak		$0.06199	per kWh	$0.06199	per kWh	
Secondary Service, Off-Peak		$0.04346	per kWh	$0.04346	per kWh	
PRIMARY & TRANSFORMER DISCOUNTS (Applicable to certain C/I customer classes)						
Pri. Voltage Energy Discount		($0.00100)	per kWh	($0.00100)	per kWh	
Pri. Voltage Demand Discount	($0.00328)	($0.00011)	per kW per day	($0.00011)	per kW per day	($0.00328)
Transformer Demand Discount	($0.10)	($0.00328)	per kW per day	($0.00328)	per kW per day	($0.10)

Appendix C

Madison Gas and Electric Company

Monitored Fuel Costs for 2009

Month	Fuel Costs	kWh	$ / kWh	Cumulative $ / kWh

January	$ 11,941,000	289,802,000	$ 0.04120	$ 0.04120
February	$ 11,370,000	268,826,000	$ 0.04230	$ 0.04173
March	$ 10,747,000	270,392,000	$ 0.03975	$ 0.04108
April	$ 8,423,000	263,200,000	$ 0.03200	$ 0.03889
May	$ 8,100,000	279,452,000	$ 0.02899	$ 0.03688
June	$ 9,547,000	282,280,000	$ 0.03382	$ 0.03635
July	$ 14,106,000	361,527,000	$ 0.03902	$ 0.03683
August	$ 11,941,000	323,485,000	$ 0.03691	$ 0.03684
September	$ 10,049,000	299,085,000	$ 0.03360	$ 0.03648
October	$ 9,860,000	290,138,000	$ 0.03398	$ 0.03623
November	$ 8,013,000	261,529,000	$ 0.03064	$ 0.03577
December	$ 9,142,000	293,454,000	$ 0.03115	$ 0.03538
Total	$ 123,239,000	3,483,170,000	$ 0.03538	$ 0.03538

Footnotes

1 *See State v. Currier*, 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

1 Present Revenue includes the Fuel Surcharge