COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO. 2003-00433
LOUISVILLE GAS AND ELECTRIC COMPANY	)	

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O R D E R

Louisville Gas and Electric Company ("LG&E"), a wholly owned subsidiary of LG&E Energy LLC ("LG&E Energy"),[1] is an electric and gas utility that generates, transmits, distributes, and sells electricity to approximately 385,000 consumers in Jefferson County and in portions of 8 counties.[2] LG&E purchases, stores, transports, distributes, and sells natural gas to approximately 312,000 consumers in Jefferson County and in portions of 15 counties.[3]

BACKGROUND

On November 24, 2003, LG&E filed a letter giving notice of its intent to file an application for approval of an increase in its electric rates to produce additional annual revenues of $63,764,203, an increase of 11.34 percent, and an increase in its gas rates to produce additional annual revenues of $19,106,269, an increase of 5.43 percent. On

[1] LG&E Energy is a Kentucky limited liability company and is an indirect subsidiary of E.ON AG ("E.ON"), a German multi-national energy corporation.

[2] The 8 counties are Bullitt, Hardin, Henry, Meade, Oldham, Shelby, Spencer, and Trimble.

[3] The 15 counties are Barren, Bullitt, Green, Hardin, Hart, Henry, Larue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Trimble, and Washington.

December 29, 2003, LG&E filed its application, which included new rates to be effective January 31, 2004 and proposals to revise, add, and delete several tariffs applicable to its electric and gas services. To determine the reasonableness of the request, the Commission suspended the proposed rates for 5 months from their effective date, pursuant to KRS 278.190(2), up to and including June 30, 2004.

LG&E's last increase in electric rates was authorized in December 1990 in Case No. 1990-00158.[4] LG&E's last increase in gas rates was authorized in September 2000 in Case No. 2000-00080.[5] LG&E was required to reduce its electric rates as part of a rate complaint, Case No. 1998-00426,[6] in January 2000.

The following parties requested and were granted full intervention: the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"); the United States Department of Defense and Other Federal Executive Agencies ("DOD"); the Division of Energy ("KDOE") of the Environmental and Public Protection Cabinet; the Kentucky Industrial Utility Customers, Inc. ("KIUC"); The Kroger Company ("Kroger"); the Kentucky Association for Community Action, Inc. ("KACA"); the Metro Human Needs Alliance ("MHNA"); and People Organized and Working for Energy Reform ("POWER").

[4] Case No. 1990-00158, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company.

[5] Case No. 2000-00080, The Application of Louisville Gas and Electric Company to Adjust Its Gas Rates and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks.

[6] Case No. 1998-00426, Application of Louisville Gas and Electric Company for Approval of an Alternative Method of Regulation of Its Rates and Service.

On January 14, 2004, the Commission issued a procedural schedule to investigate LG&E's rate application. The schedule provided for discovery, intervenor testimony, rebuttal testimony by LG&E, a public hearing, and an opportunity for the parties to file post-hearing briefs. On March 23, 2004, the AG, DOD, KDOE, KIUC, Kroger, KACA, MHNA, and POWER filed their testimony. Also on March 23, 2004, the Commission granted LG&E's motion to consolidate into this case that portion of Case No. 2003-00396 relating to a new LG&E tariff for Non-Conforming Load ("NCL") customers.[7] On March 31, 2004, the Commission granted a joint motion by LG&E, the AG, and KIUC to consolidate Case No. 2003-00335, an investigation of the Earnings Sharing Mechanism ("ESM") for LG&E, into this proceeding.[8] LG&E filed its rebuttal testimony on April 26, 2004.

On April 28, 2004, an informal conference was held to discuss procedural matters and the possible resolution of pending issues. Additional conferences were held on April 29, 2004 and May 3, 2004. The public hearing was convened on May 4,

[7] Case No. 2003-00396, Tariff Filing of Kentucky Utilities Company and Louisville Gas and Electric Company for Non-Conforming Load Customers. On February 13, 2004, LG&E filed its motion to consolidate Case No. 2003-00396 with its rate case. On March 19, 2004, LG&E filed an amendment to its motion to clarify that it was seeking to have Case No. 2003-00396 bifurcated and the respective portion consolidated with the LG&E rate case.

[8] Case No. 2003-00335, An Investigation Pursuant to KRS 278.260 of the Earnings Sharing Mechanism Tariff of Louisville Gas and Electric Company. LG&E, the AG, and KIUC filed their joint motion on December 18, 2003. On January 16, 2004, LG&E, the AG, and KIUC filed a letter requesting that their motion to consolidate be held in abeyance. They filed another letter on March 12, 2004, requesting the Commission to rule on their motion to consolidate.

2004,[9] at which time the parties indicated that significant progress had been made toward resolving many of the issues, and they requested the hearing be delayed to allow additional discussions.[10] This request was granted, and on May 5, 2004, the parties announced a tentative agreement on two documents that resolved many of the issues. One document, titled "Settlement Agreement" ("ESM Settlement"), provided for the orderly discontinuance of the ESM. The other document, titled "Partial Settlement Agreement, Stipulation and Recommendation" ("Partial Settlement and Stipulation"), addressed all the remaining issues, including the NCL tariff, and resolved many but not all of the issues raised in LG&E's rate case.

Because the Partial Settlement and Stipulation did not resolve appropriate revenue increase and depreciation rates for LG&E's electric operations,[11] the hearing proceeded in the afternoon of May 5, 2004 with testimony being presented by LG&E and the AG. The hearing on those issues concluded on May 6, 2004. The parties subsequently finalized the ESM Settlement and the Partial Settlement and Stipulation

[9] For administrative efficiency, the public hearing for this case and the general rate case for the Kentucky Utilities Company ("KU") were held simultaneously. See Case No. 2003-00434, An Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company.

[10] Transcript of Evidence ("T.E."), Volume I, May 4, 2004, at 36-39 and 57-60.

[11] At the beginning of the hearing on May 5, 2004, the AG had not agreed with the other parties on the revenue increases and depreciation rates for both LG&E's electric and gas operations. During the hearing on May 5, 2004, the AG reached agreement on the revenue increase for LG&E's gas operations. See T.E., Volume II, May 5, 2004, at 40-41.

and, on May 12, 2004, they filed the final versions of both documents.[12] During the hearing, or by subsequent written request, the DOD, KDOE, KIUC, Kroger, KACA, MHNA, and POWER withdrew their respective prefiled testimonies and responses to data requests on those testimonies. The AG also withdrew his prefiled testimony on all issues except LG&E's electric revenue requirement and depreciation rates.[13] A hearing was then held on that date to receive testimony on the reasonableness of both documents.

On June 4, 2004, LG&E and the AG timely filed briefs in accordance with the procedural schedule. All information requested at the public hearing has been filed and the case now stands submitted for a decision.

ESM SETTLEMENT

LG&E previously submitted its calendar year 2003 ESM filing pursuant to its ESM tariff, and it was docketed as Case No. 2004-00069.[14] In that filing, LG&E calculated its 2003 ESM billing factor to be 2.282 percent for April 1, 2004 through April 30, 2004, and 2.360 percent for May 1, 2004 through March 31, 2005.[15]

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[12] The ESM Settlement is attached hereto as Appendix A, and the Partial Settlement and Stipulation is attached hereto as Appendix B. Both documents are incorporated into this Order as if fully set forth herein.

[13] T.E., Volume IV, May 12, 2004, at 8-9 and 12-15.

[14] Case No. 2004-00069, Louisville Gas and Electric Company's Annual Earnings Sharing Mechanism Filing for Calendar Year 2003.

[15] Under the provisions of its ESM tariff, LG&E is required to file a determination of a balancing adjustment to the current ESM billing factor, reflecting a true-up for any over- or under-collections experienced with the previous ESM billing factor. The revision in the 2003 ESM billing factor reflects the balancing adjustment for the 2002 ESM billing factor.

Under the terms of the ESM Settlement, the parties recommend that an Order be issued in Case No. 2004-00069 approving LG&E's 2003 ESM billing factor as filed and authorize LG&E to bill them through March 31, 2005. LG&E would then collect and retain all this revenue. No later than May 2005, LG&E is to perform a final balancing adjustment to reconcile any over- or under-collection of the 2003 ESM revenues as billed from April 2004 through March 2005. Effective July 1, 2004, the ESM will be discontinued and LG&E will waive its rights to make any billings or seek any collections under its ESM tariff for its operations during the first 6 months of 2004.

The Commission has reviewed the ESM Settlement and finds that it constitutes a reasonable resolution of the issues related to the continuation of LG&E's ESM. When the Commission offered the ESM to LG&E in 2000, the intent was that this alternative form of regulation would provide sufficient incentives to LG&E to improve its performance while reducing the business risks inherent in over- and under-earnings. The management audit performed for the Commission concluded,[16] and LG&E confirmed in its own testimony, that the ESM has not incented LG&E to operate any differently than it would have without an ESM. In light of these results, the termination of the ESM as currently configured is reasonable. Therefore, the Commission will

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[16] The Barrington-Wellesley Group, Inc. ("BWG") performed the ESM management audit and issued its final report on August 31, 2003. BWG determined that the ESM was an effective alternative to traditional cost of service regulation, although it did recommend some modifications to the current structure. The BWG report stated "However, it is the LG&E/KU management's position that the ESM program did not change management behavior. Management contends that LG&E and KU already had a strong continuous improvement program and that the ESM reinforced this behavior and added a regulatory mechanism for dealing with the ebb and flow of earnings over time." BWG Report at IV-1.

approve the ESM Settlement in its entirety. An Order confirming this will be issued in Case No. 2004-00069 in the near future.

The Commission notes that the ESM Settlement provides that nothing therein will bar a party from seeking, or the Commission from reinstating, an ESM which is designed to accomplish reasonable and valid regulatory objectives. While the Commission is now approving the termination of the current ESM because it did not achieve its intended purpose, we will take this opportunity to reaffirm our support for alternative rate-making mechanisms. LG&E is encouraged to continue considering alternative regulation, and, if it decides to propose one in the future, it should do so after seeking input from its customer representatives.

PARTIAL SETTLEMENT AND STIPULATION

Unanimous Provisions

Gas Operations

The Partial Settlement and Stipulation reflects a unanimous resolution of all issues raised in LG&E's gas rate case, except its depreciation rates. The gas issues thus resolved include the amount of the revenue increase, the revenue allocations and rate design, and the proposed changes in the terms and conditions of gas service. The major provisions of the Partial Settlement and Stipulation as they relate to LG&E's gas operations are as follows:

- Effective July 1, 2004, LG&E's gas operation revenues should be increased by $11,900,000.

- The gas rates as set forth in Exhibit 1 to the Partial Settlement and Stipulation are the fair, just, and reasonable rates for LG&E's gas operations and those rates should be approved by the Commission.

- LG&E's gas purification and gas storage loss expenses should be recovered as part of its Gas Supply Clause mechanism.

- The notice period for an Operational Flow Order pursuant to LG&E's Rate FT should be 24 hours.

- All miscellaneous charges applicable to gas operations should be approved as proposed by LG&E, except that the Disconnect-Reconnect Charge should be $20.00.

- The monthly residential gas customer charge should be $8.50 per month and all other customer charges applicable to gas operations should be implemented as proposed by LG&E.

- LG&E will withdraw its Standard Riders for Summer Air Conditioning Service for its gas operations and customers served under those riders will take service under otherwise applicable rate schedules.

Electric Operations

The Partial Settlement and Stipulation reflects a unanimous resolution of a substantial number of the issues raised, including the revenue allocations, rate design issues, and LG&E's proposed changes in its electric operations terms and conditions of service. The major provisions of the Partial Settlement and Stipulation for LG&E's electric operations that have been unanimously agreed to are as follows:

- LG&E will establish a pilot time-of-day program for commercial customers with a monthly demand between 250 kW and 2,000 kW.[17]

- Future Commission Orders approving cost recovery of LG&E's environmental projects pursuant to KRS 278.183 are to be based upon an 11.00 percent return on common equity until directed by Order of the Commission that a different rate of return shall be utilized.

- All costs associated with LG&E's 1995 environmental compliance plan will be removed from LG&E's monthly environmental surcharge filings and will be recovered in LG&E's base rates.

[17] Reflects a stipulation agreement between LG&E and Kroger dated May 4, 2004 and attached to the Partial Settlement and Stipulation as Exhibit 2.

- LG&E will establish a real time pricing pilot program for a 3-year term and participation will be limited to up to 50 customers under Rate R and up to 50 customers under Rate GS; customers under Rate LP are to be eligible for inclusion in the second year of the pilot program.

- All miscellaneous charges applicable to electric operations should be approved as proposed by LG&E except that the Disconnect-Reconnect Charge should be $20.00.

- The monthly residential electric customer charge should be $5.00 per month; Rate GS electric single phase should be $10.00 per month; Rate GS electric three phase should be $15.00 per month; and all other customer charges applicable to electric operations should be implemented as proposed by LG&E.

- LG&E Rate GS should be available to electric customers with connected loads up to 500 kW.

- LG&E will not bill an additional customer charge to Rate GS customers formerly taking service under the Rider for Electric Space Heating Service under Rate GS.

- LG&E will eliminate the seasonal rate structure for Rate RS and will implement a non-seasonally differentiated rate structure for Rate RS.

- LG&E will offer a Curtailable Service Rider ("CSR1") to current customers who meet the eligibility requirements set forth in LG&E's proposed CSR1, subject to specific terms and conditions.

- New customers not currently served by an existing CSR will be eligible to take curtailable service under a new CSR tariff ("CSR2") as proposed by LG&E, except such customers will be able to buy through a request for curtailment only after having been on the CSR2 service for 3 years with no failure to curtail when requested.

- The NCL service should be renamed the "large industrial-time of day" ("LI-TOD"), and the LI-TOD should be the same as the NCL tariff proposed in Case No. 2003-00396, subject to changes outlined in the Partial Settlement and Stipulation.

<u>Gas and Electric Operations</u>

The Partial Settlement and Stipulation also contains the following provisions relating to both the gas and electric operations that were unanimously agreed to:

- Unless the Commission has already modified or terminated the Value Delivery Team ("VDT") surcredit in a subsequent rate case, 6 months prior to the expiration of the 60-month period in which the VDT surcredits are in operation, LG&E will file with the Commission a plan for the future rate-making treatment of the VDT surcredits, shareholder savings, amortization of VDT costs, and all other VDT-related issues. The VDT surcredit tariff will remain in effect following the 60th month until the Commission enters an Order on the future rate-making treatment.

- In conjunction with the AG, KACA, MHNA, and POWER, LG&E will file plans for program administration with the Commission for a year-round Home Energy Assistance ("HEA") program based solely upon a 10-cent per residential meter per month charge for a period of 3 years. The HEA programs will be operated by existing social service providers with experience in operating low-income energy assistance programs, and the providers will be entitled to recover actual operating expenses not to exceed 10 percent of total HEA funds collected. The HEA programs to be filed will commence on October 1, 2004. The Commission's approval of the Partial Settlement and Stipulation will constitute approval of the HEA parameters as proposed, subject to further review by the Commission of additional programmatic details.

- Those parties that are also parties to the Franklin Circuit Court actions agree that upon Commission approval of the Partial Settlement and Stipulation, they will jointly move the Franklin Circuit Court for the entry of an order dismissing the pending HEA and Pay As You Go appeals, Civil Action Nos. 02-CI-00991 and 03-CI-00634, respectively.

- LG&E will phase out its Pay As You Go program by limiting the program to existing customers and by removing those meters from existing customers as requested, as meters fail, or as customers move off the system. LG&E reserves the right to completely terminate the program upon 60 days advance notice to the Commission. LG&E will not seek approval of a new prepaid metering program for a period of 5 years and any such program proposed thereafter will be subject to prior Commission approval.

<u>Non-unanimous Provisions</u>

The partial Settlement and Stipulation contains additional provisions that relate to issues in the rate case that were agreed to by all parties except the AG. Consequently, the Commission cannot accept these non-unanimous provisions as resolutions of the issues covered. The non-unanimous provisions which were agreed to by LG&E and all intervenors except the AG are as follows:

- Effective July 1, 2004, LG&E's electric operation revenues should be increased by $43,400,000.

- The electric rates as set forth in Exhibit 1 to the Partial Settlement and Stipulation are the fair, just, and reasonable rates for LG&E's electric operations and those rates should be approved by the Commission.

- LG&E's depreciation rates should remain the same as approved in the Order of December 3, 2001 in Case No. 2001-00141,[18] until the approval by the Commission of new depreciation rates for LG&E. LG&E must seek approval by filings made in its next general rate case or June 30, 2007, whichever occurs earlier. The new depreciation filings are to be based on plant in service as of a date no earlier than 1 year prior to such filing. From and after the effective date hereof, LG&E will maintain its books and records so that net salvage amounts may be identified.

Gas Operations

LG&E and all the intervenors unanimously agree that the provisions in the Partial Settlement and Stipulation, which relate to LG&E's gas operations, are reasonable and should be accepted by the Commission as a complete resolution of those issues.

The Partial Settlement and Stipulation sets forth only the amount of revenue increase agreed to, not the underlying calculations and adjustments. In determining the overall reasonableness of the proposed $11,900,000 increase in LG&E's gas operations annual revenues, the Commission has evaluated LG&E's proposed adjustments to capital, rate base, operating revenues, and operating expenses in light of our normal rate-making treatment. In addition, consideration has been given to the rates of return on common equity authorized by the Commission in recent rate cases. Based on a

[18] Case No. 2001-00141, Application of Louisville Gas and Electric Company for an Order Approving Revised Depreciation Rates.

review of all these factors and the evidence of record, the Commission finds that the level of revenue provided for in the Partial Settlement and Stipulation for LG&E's gas operations should produce earnings that fall within in a range reasonable for both LG&E and its gas ratepayers. The $11,900,000 gas revenue increase provided for in the Partial Settlement and Stipulation will result in fair, just, and reasonable gas rates for LG&E.

Electric Operations

In its application, LG&E proposed an annual increase in its electric revenues of $63,764,203. The AG proposed an annual increase in LG&E's electric revenues of $12,141,000. In the Partial Settlement and Stipulation, LG&E and all the intervenors except the AG agree that an annual increase in electric revenues of $43,400,000 is reasonable. Since all parties have not reached a unanimous settlement on LG&E's electric revenues, the Commission must consider all the record evidence on this issue, including the issue of depreciation rates, and render a decision. This decision will be based on a determination, for LG&E's electric operations, of its capital, rate base, operating revenues, and operating expenses as would normally be done in a rate case.

TEST PERIOD

LG&E proposes the 12-month period ending September 30, 2003 as the test period for determining the reasonableness of its proposed electric rates. The AG also utilized this 12-month period. The Commission finds it is reasonable to utilize the 12-month period ending September 30, 2003 as the test period in this proceeding. In utilizing a historic test period, the Commission has given full consideration to appropriate known and measurable changes.

RATE BASE

Rate Base Allocation Ratio

LG&E's application proposed a test-year-end electric rate base of $1,675,374,829,[19] and this amount was accepted by the AG.[20] The test-year-end electric rate base is divided by LG&E's test-year-end total company rate base to derive a rate base allocation ratio ("allocation ratio"). This allocation ratio is then applied to LG&E's total company capitalization to determine LG&E's electric capitalization. The allocation ratio uses the test-year-end rate base before recognizing rate-making adjustments applicable to either the electric or gas operations. LG&E and the AG used an allocation ratio of 84.13 percent.[21]

The Commission has reviewed the calculation of the test-year-end electric rate base and agrees with the calculation, except for the treatment of accumulated deferred income taxes ("ADIT") associated with Statement of Financial Accounting Standards ("SFAS 109") No. 109. The balance for ADIT used in the determination of rate base reflects the account balances for four accounts in the Uniform System of Accounts ("USoA"): Account Nos. 190, 281, 282, and 283.[22] Account No. 190 normally has a debit balance, while the remaining three accounts normally have credit balances. The

[19] Rives Direct Testimony, Rives Exhibit 3, page 1 of 2.

[20] Henkes Electric Direct Testimony, Schedule RJH-3.

[21] Rives Direct Testimony, Rives Exhibit 3, page 1 of 2.

[22] Account No. 190, Accumulated Deferred Income Taxes; Account No. 281, Accumulated Deferred Income Taxes – Accelerated Amortization Property; Account No. 282, Accumulated Deferred Income Taxes – Other Property; and Account No. 283, Accumulated Deferred Income Taxes – Other. The Commission notes that LG&E's financial statements do not show a balance for Account No. 281.

balances in these accounts are netted together to determine the amount to be included in the rate base calculations. If the net ADIT amount is a net credit balance, it is shown in the rate base calculations as a positive deduction, while a net debit balance is shown as a negative deduction.

When LG&E calculated its test-year-end rate base, it reported the total net credit balance resulting from Account Nos. 190, 282, and 283 as ADIT.[23] The subaccounts making up the balances for these three accounts included SFAS 109 ADIT subaccounts.[24]

LG&E then reported the net balance of Account Nos. 182.3 and 254[25] as its SFAS 109 ADIT. The SFAS 109 ADIT amounts from Account Nos. 190, 282, and 283 have a net debit balance, while the SFAS 109 amounts from Account Nos. 182.3 and 254 have a net credit balance. The erroneous inclusion of the balances from Account Nos. 182.3 and 254 has the effect of partially offsetting the SFAS 109 ADIT recorded in Account Nos. 190, 282, and 283. This results in the deductions section of the rate base being overstated and the total rate base being understated. The correct presentation of the ADIT balances is the separation of the SFAS 109 ADIT from the regular ADIT.

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[23] Consistent with previous Commission decisions, LG&E also excluded ADIT associated with its supplemental executive retirement income plan from the ADIT balance included in the rate base calculation. See Response to the Commission Staff's Second Data Request dated February 3, 2004, Items 15(d)(1) and 15(d)(2).

[24] Response to the Commission Staff's First Data Request dated December 19, 2003, Item 13(c), pages 5, 8, and 9 of 19.

[25] Account No. 182.3, Other Regulatory Assets and Account No. 254, Other Regulatory Liabilities. The subaccount balances used in the calculation are identified as SFAS 109 taxes. For Account No. 254, LG&E used the subaccount balances for 254001 through 254004. See Response to the Commission Staff's First Data Request dated December 19, 2003, Item 13(c), pages 3 and 8 of 19.

The Commission believes the ADIT and SFAS 109 ADIT included in the rate base calculations should reflect only the balances as recorded in Account Nos. 190, 282, and 283. The calculation of LG&E's test-year-end electric operations and total company rate bases and the allocation ratio are shown in Appendix D. Therefore, the Commission has determined that LG&E's allocation ratio is 84.33 percent.

Pro Forma Electric Rate Base

LG&E calculated a pro forma electric rate base of $1,468,685,936,[26] while the AG proposed a pro forma electric rate base of $1,479,108,000.[27] Both calculations reflected the approach utilized by the Commission in previous rate cases to determine the pro forma rate base, but neither calculation recognized certain adjustments normally included therein.

While LG&E removed the utility plant, construction work in progress, and accumulated depreciation associated with its Post-1995 environmental compliance plan ("Post-1995 Plan"), it should have removed the ADIT associated with the Post-1995 Plan. Excluding the Post-1995 Plan ADIT is consistent with the Commission's treatment of this item in Case No. 1998-00426.[28] LG&E should have included in its balance for accumulated depreciation its proposed increase in electric depreciation expense, an adjustment the Commission has consistently recognized.[29] Finally, LG&E

[26] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 39.

[27] Henkes Electric Direct Testimony, Schedule RJH-3.

[28] Case No. 1998-00426, final Order dated January 7, 2000, at 60-62 and Appendix A, and rehearing Order dated June 1, 2000, at 1-4.

[29] Case No. 2000-00080, final Order dated September 27, 2000, at 18-20.

should not have included in its materials and supplies the 13-month average balance for carbide lime inventory because that inventory has been written off.

The AG's pro forma electric rate base did include adjustments for the Post-1995 Plan ADIT, the AG's proposed reduction in depreciation expense, and the adjustment to remove the carbide lime inventory. However, the AG should have recalculated the cash working capital allowance to reflect the impact of all his proposed expense adjustments.

The Commission has determined LG&E's pro forma electric rate base for rate-making purposes by beginning with the test-year-end electric rate base utilized to determine the allocation ratio, and then incorporating the adjustments discussed previously in this Order. The adjustment to accumulated depreciation reflects the decrease in test-year depreciation expense discussed later in this Order. The cash working capital allowance has been adjusted to reflect the accepted pro forma adjustments to operation and maintenance expenses as discussed later in this Order.[30]

Based upon the previous findings, we have determined LG&E's pro forma electric rate base for rate-making purposes as of September 30, 2003 to be as follows:

[30] The adjustments made to determine the pro forma electric rate base are listed in Appendix C.

Total Utility Plant in Service	$3,020,944,877
Add:	
Materials & Supplies	55,499,409
Prepayments	2,882,693
Cash Working Capital Allowance	55,028,689
Subtotal	$ 113,410,791
Deduct:	
Accumulated Depreciation	1,336,898,715
Customer Advances	507,146
Accumulated Deferred Income Taxes	325,490,421
SFAS 109 Accumulated Deferred Income Taxes	(34,633,001)
Investment Tax Credit (prior law)	3,943
Subtotal	$1,628,267,224
Pro Forma Electric Rate Base	$1,506,088,444

Reproduction Cost Rate Base

LG&E presented a total company reproduction cost rate base of $3,691,607,919, and an electric operations reproduction cost rate base of $3,036,157,656.[31] The costs were determined principally by indexing the surviving plant and equity using the Handy-Whitman Index of Public Utility Construction Costs and the Consumer Price Index.[32] The Commission has given consideration to the proposed reproduction cost rate base, but finds that using LG&E's historic cost for rate base is appropriate and consistent with precedents for LG&E and other utilities within Kentucky.

CAPITALIZATION

LG&E proposed an adjusted electric operations capitalization of $1,485,701,357.[33] Included in its electric capitalization were adjustments for the Job

[31] Rives Direct Testimony, Rives Exhibit 4.

[32] Rives Direct Testimony at 27.

[33] Rives Direct Testimony, Rives Exhibit 2, page 1 of 2.

Development Investment Tax Credit ("JDIC"), the removal of 25 percent of inventories associated with Trimble County Unit 1,[34] LG&E's equity investment in the Ohio Valley Electric Corporation ("OVEC"), the removal of reimbursed capital invested to repair the combustion turbines at the E. W. Brown Generating Station, the removal of LG&E's Post-1995 environmental compliance plan investments, and to reverse LG&E's minimum pension liability adjustment to Other Comprehensive Income. LG&E allocated the minimum pension liability adjustment to common equity only, while it allocated all other proposed adjustments on a pro rata basis to all components of capitalization.

The AG proposed an adjusted electric operations capitalization of $1,460,257,000.[35] The AG agreed with all of LG&E's adjustments to capitalization except the adjustment for the minimum pension liability. Both LG&E and the AG determined the electric capitalization by multiplying LG&E's total company capitalization by the allocation ratio described above. This is consistent with the approach used by the Commission in previous LG&E rate cases.

Minimum Pension Liability

LG&E adopted SFAS No. 130, *Reporting Comprehensive Income*, on January 1, 1998. SFAS No. 130 requires a company to report a measure of all changes in equity, not just resulting from transactions and economic events currently reflected in the determination of net income. The changes that are not currently reflected in net income are called Other Comprehensive Income items. Other Comprehensive Income items

[34] The 25 percent adjustment for Trimble County inventories is consistent with the Commission's decision in Case No. 1990-00158. See Case No. 1990-00158, final Order dated December 21, 1990 at 14-15.

[35] Henkes Electric Direct Testimony, Schedule RJH-2.

include foreign currency translation changes, unrealized holding gains and losses on available-for-sale securities, mark-to-mark gains and losses on cash flow hedges, and minimum pension liability. For each of these items, the liability is fully recognized on the balance sheet but not yet on the income statement, because the financial impact that unrealized changes in value may eventually cause have not occurred and have not been included in the income statement under generally accepted accounting principles.[36] A minimum pension liability occurs when, as of a measurement date,[37] the discounted benefits previously earned by participants in the pension plan exceed the market value of the pension trust assets, thus representing an unfunded pension benefit earned by plan participants to date.

For calendar year 2002, due to the below-average performance of the stock market and low interest rates, LG&E determined it had a total company minimum pension liability of $30,242,903, with $25,443,354 applicable to its electric operations.[38] LG&E recorded the $25,443,354 as a component of its Other Comprehensive Income and reduced its equity accordingly. LG&E argued that it would be an unfair regulatory policy to reduce common equity today for a loss not yet recorded on the income statement, and a loss that may or may not actually be incurred.[39] In its application, LG&E requested that it be permitted to reverse the entry for the minimum pension

[36] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 15(a)(3), page 8 of 16.

[37] The measurement date is normally the last day of a calendar year.

[38] Rives Direct Testimony, Rives Exhibit 2, page 2 of 2.

[39] Rives Direct Testimony at 24.

liability and record a regulatory asset to effect the reversal. The minimum pension liability is recalculated every year and, consequently, the regulatory asset would be revised and adjusted annually. Because of this feature, LG&E contended that the regulatory asset would not have to be amortized.

The AG opposed the proposed adjustment citing three reasons. First, the AG contended that the equity adjustment had actually been made and was an actual known and measurable adjustment to capitalization. Because of this fact, the AG believed that reversing the write-down was not consistent with previous Commission decisions. Second, the AG did not believe the creation of the regulatory asset as proposed by LG&E was consistent with or allowed by SFAS No. 71. The AG believes that regulatory assets established under SFAS No. 71 are recovered through amortization of the asset to the income statement, while the proposed regulatory asset for the minimum pension liability would be extinguished through balance sheet accounting. Lastly, the AG expressed concern that the establishment of the regulatory asset for the minimum pension liability would result in a presumption that the underlying costs are recoverable from ratepayers in the future and any prudence review of those costs in the future would be precluded.[40]

LG&E disagreed with the AG's arguments, noting that the write-down is not a permanent adjustment to its equity balance since the minimum pension liability will change with each measurement date. LG&E argued that the AG's reliance on the Commission's decision in Case No. 1998-00426 had no bearing on how the reversal of the write-down for the minimum pension liability should be treated. As to establishing a

[40] Henkes Direct Testimony at 10-12.

regulatory asset under SFAS No. 71, LG&E stated that the Federal Energy Regulatory Commission ("FERC") has issued an accounting decision permitting the establishment of the minimum pension liability regulatory asset for utilities with cost-based regulated rates.[41] LG&E dismissed the AG's concern that the creation of the regulatory asset would preclude a prudence review of pension costs in the future, noting that LG&E had not asserted such a claim and that the AG's witness had agreed that the FERC decision letter had eliminated the prudence concern.[42]

The Commission has not previously addressed this issue. The accounting treatment for the minimum pension liability is in effect a means of disclosing a contingency, since there is no corresponding change in the company's current pension expense recognized in the income statement. The minimum pension liability required by SFAS No. 130 and the proposed regulatory asset are unique, in that the balance is determined periodically and the recorded liability and proposed asset are adjusted accordingly. In the event the market value of the pension trust assets exceed the discounted benefits previously earned by participants in the pension plan, there would be no minimum pension liability and no corresponding adjustment to the company's equity.

[41] Rives Rebuttal Testimony at 8. In a request dated October 31, 2003, the Edison Electric Institute filed a request with FERC seeking an accounting ruling supporting the creation of a regulatory asset for those utilities required to recognize a minimum pension liability as part of the determination of Other Comprehensive Income. On March 29, 2004, FERC's Deputy Executive Director and Chief Accountant issued a decision in FERC Docket No. AI04-2-000 allowing for the creation of the regulatory asset for accounting purposes. See Rives Rebuttal Testimony, SBR Rebuttal Exhibit 1.

[42] Joint Post-Hearing Brief of LG&E and KU at 27.

The Commission finds LG&E's adjustment to be reasonable. The write-down of LG&E's equity due to the minimum pension liability is not a permanent event, with the adjustment recalculated at the measurement date of the pension plan. Consequently, this adjustment to equity is not the same as the adjustment cited by the AG from Case No. 1998-00426. The accounting decision issued by FERC addresses the AG's concerns regarding the legitimacy of creating the regulatory asset, and that the regulatory asset will not be amortized and recognized as a current operating expense.[43] Lastly, the Commission stresses that establishing this regulatory asset creates no presumption that the underlying pension costs are either reasonable or recoverable from ratepayers in the future.

Based upon these findings, LG&E's proposal is accepted and the equity in its electric operations capitalization is increased by $25,443,354.

SFAS No. 143 – Asset Retirement Obligation ("ARO") Adjustment

LG&E adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, on January 1, 2003. Under SFAS No. 143, if a utility determines it has a legally enforceable ARO, the utility must measure and record the liability for the ARO on its books. The liability must be recorded at fair market value in the period that the liability is incurred. A corresponding and equivalent ARO asset is also recorded on the utility's books to recognize the cost of removal as an integral part of the cost of the associated tangible asset. Utilities are also required to recognize the cumulative effect impact on their financial statements resulting from the adoption of SFAS No. 143. The cumulative

[43] The Commission notes that the FERC accounting decision was issued after the AG had filed his direct testimony in this case.

effect impact represents the ARO asset depreciation and ARO liability accretion that would have been recorded had the asset and liability been recorded when the original asset was placed into service. On April 9, 2003, FERC issued Order No. 631,[44] which generally adopted the requirements of SFAS No. 143.

In Case No. 2003-00426,[45] LG&E sought approval of an accounting adjustment to its ESM for calendar year 2003 to reflect its adoption of SFAS No. 143 in 2003. LG&E and KIUC, the only intervenor in that case, filed a stipulation that resolved all issues raised therein. Among other things, the stipulation provided that, "The ARO assets, related ARO asset accumulated depreciation, ARO liabilities, and remaining regulatory assets associated with the adoption of SFAS No. 143 will be excluded from rate base."[46]

Now, LG&E has proposed to remove the cumulative effect of the accounting change resulting from the adoption of SFAS No. 143[47] and to remove the ARO assets from the determination of its pro forma rate base.[48] However, LG&E did not propose any adjustment to its electric operations capitalization corresponding with the rate base

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[44] FERC Order No. 631 is the final rule in *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, Docket No. RM02-7-000.

[45] Case No. 2003-00426, Application of Louisville Gas and Electric Company for an Order Approving an Accounting Adjustment to be Included in Earnings Sharing Mechanism Calculations for 2003.

[46] Case No. 2003-00426, final Order dated December 23, 2003 at 3.

[47] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.25.

[48] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 39, page 1 of 2, line 5. The adjustment to the pro forma electric rate base was $4,585,010.

adjustment for the ARO asset. In order to be consistent with LG&E's efforts to remove the impact of the adoption of SFAS No. 143, it is necessary to exclude the ARO assets from LG&E's electric capitalization. Such an adjustment is also consistent with previous decisions by the Commission when items are removed from the calculation of rate base. Therefore, the Commission has reduced LG&E's electric capitalization, on a pro rata basis, by $4,585,010.

Based on the findings herein, the Commission has determined that LG&E's test-year-end electric capitalization should be $1,484,965,466. The calculation of the electric capitalization is shown in Appendix E.

REVENUES AND EXPENSES

For the test year, LG&E reported actual net operating income from electric operations of $108,683,393.[49] LG&E proposed a series of adjustments to revenues and expenses to reflect more current and anticipated operating conditions, resulting in an adjusted net operating income from electric operations of $68,010,218.[50] The AG also proposed numerous revenue and expense adjustments, resulting in adjusted net operating income from electric operations of $87,108,000.[51] The Commission finds that 20 of the adjustments, proposed in LG&E's application and accepted by the AG, are reasonable and will be accepted. During the proceeding, LG&E identified and corrected errors in several other adjustments originally proposed in its application. The Commission finds that three of these other adjustments, as corrected by LG&E and

[49] Rives Direct Testimony, Rives Exhibit 1, page 1 of 3, line 1.

[50] Id., page 3 of 3, line 44.

[51] Henkes Electric Direct Testimony, Schedule RJH-4.

accepted by the AG, are reasonable and they will also be accepted. All of these 23 adjustments are set forth in detail in Appendix F, which is attached hereto.

The Commission makes the following modifications to the remaining proposed adjustments:

Unbilled Revenues

LG&E proposed an adjustment to eliminate the effect of unbilled electric revenues for rate-making purposes. The rationale for such an adjustment is to develop a better match of test-year revenues and expenses, using as-billed revenues for rate-making purposes rather than the revenues recorded on an accrual basis for accounting purposes. LG&E made its adjustment by shifting unbilled revenues for the month immediately preceding the test year into the test year (when they were actually billed) and shifting unbilled revenues for the last month of the test year to the first month after the test year. This has the effect of netting the amount of unbilled revenues at test-year-end and at the beginning of the test year. LG&E's adjustment reduced electric revenues by $1,867,000.

The AG did not oppose LG&E's unbilled revenues adjustment, but he did propose a corresponding electric expense adjustment to reflect the expense side of an adjustment that reduces test-year sales volumes by 4,095,000 Kwh. The AG calculated an expense reduction of $1,042,000 based on the 55.79 percent operating ratio used by LG&E to calculate its customer growth adjustment.

LG&E objected to the AG's expense adjustment. Since the revenues eliminated by LG&E's adjustment included the recovery of environmental surcharge, fuel clause and demand-side management costs that are removed from test-year operating results through various other adjustments, LG&E argued that any mismatch that the AG was attempting to correct is already accounted for in adjustments made specifically to address those items of expense. LG&E also stated that, to the extent that other factors impact the calculation of unbilled revenues, such as changes in the number of customers, plant closings or customer rate switching, the pro forma adjustments it proposed for those items properly normalize for those factors. LG&E also noted that the Commission had accepted similar unbilled revenues adjustments in its last electric and its last gas rate cases.

The AG's arguments in support of its expense adjustment fail to demonstrate a link between unbilled revenues and expenses sufficient to create a mismatch of revenues and expenses absent an adjustment to reduce expenses. To the extent that such a link does exist, LG&E's arguments convince us that any resulting mismatch is adequately mitigated by the various normalization adjustments included in its rate application. Based on all of the evidence on this issue, we find the AG's expense adjustment to be unnecessary and we will accept LG&E's unbilled electric revenue adjustment as proposed.

Year-End Customer Adjustment

LG&E proposed to annualize its test-year electric revenues based on the number of customers served at test-year-end. Its adjustment was based on a comparison of the number of electric customers at year-end to the 12-month average for the test year for each customer class. It proposed a corresponding electric expense adjustment, based on an operating ratio of 55.79 percent of the revenue adjustment, to reflect the related increase in variable operating expenses. LG&E's proposed adjustment increased electric revenues by $2,614,347 and electric expenses by $1,458,544.

The AG proposed an alternative customer growth adjustment. For the residential class, he calculated an increase in revenues based on a trend of customer growth over the period 1999-2003, while for the remaining classes he proposed comparing a 13-month average to the year-end number of customers. For his expense adjustment, the AG used the same operating ratio approach used by LG&E. The AG proposed this same trend approach, which was accepted by the Commission, for Delta Natural Gas Company in Case No. 1997-00066.[52] The AG's proposed adjustment increased electric revenues by $3,247,228 and increased electric expenses by $1,811,628.

LG&E objected to the AG basing an adjustment on customer growth trends from a period largely outside the test year. LG&E stated that, in making a year-end adjustment, the only relevant factor is how year-end customers compare to test-year average customers. LG&E also noted that adjustments based on a 12-month average had been accepted by the Commission in previous LG&E rate cases.

Although the Commission strives for consistency on these issues, we recognize that we have accepted different methodologies to calculate customer growth adjustments in prior rate cases.[53] However, each case is decided on its merits, and each adjustment is based on the evidence of record. In this record, the methods

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[52] Henkes Electric Direct Testimony at 35.

[53] See Case No. 1990-00158, December 21, 1990 Order at 40; Case No. 1998-00455, Application of Grayson Rural Electric Cooperative Corporation for an Adjustment of Rates, final Order dated July 8, 1999 at 4; and Case No. 2000-00373, The Application of Jackson Energy Cooperative Corporation for an Adjustment of Rates, final Order dated May 21, 2001 at 11-12.

presented by both parties have been previously accepted.[54] Based on the reasoning set forth in LG&E's rebuttal testimony, we find the AG's trend analysis method to be the least appropriate method for determining this adjustment. However, there is another method in this record, one that compares year-end customers to a 13-month average, rather than a 12-month average, and it has also been accepted in the past.

The Commission finds that using a 13-month average is more appropriate to calculate the customer growth adjustment than the 12-month average proposed by LG&E. A 13-month average, which includes the last month immediately prior to the first month of a test year, better recognizes the number, or balance, of an item as of the beginning of the test year. This approach is used to derive average balances in other areas, such as materials and supplies, prepayments, and fuel inventories.

In response to a data request, LG&E provided revisions to its original adjustment to reflect a 13-month average.[55] Considering the arguments regarding the use of 12-month or 13-month averages, the Commission will accept the adjustment based on a 13-month average, as reflected in LG&E's data response. The result is an increase in electric revenues of $2,951,037 and an increase in electric operating expenses of $1,646,384. These amounts will be recognized in determining LG&E's revenue requirements.

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[54] Another approach that has also been accepted in prior cases is based on customer growth as measured by comparing the number of customers at the first of the year to those at the end of the year.

[55] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 28.

Depreciation Expense

LG&E proposed to increase its electric depreciation expense by $8,959,749 over its test-year actual level. This increase was based on its electric plant balances as of September 30, 2003, and the application of new depreciation rates as proposed in this proceeding. LG&E's new depreciation study was based on utility plant in service as of December 31, 2002 and was developed utilizing the Straight Line Method, the Broad Group Procedure, and the Average Remaining Life Technique.[56] LG&E's current depreciation rates were approved in Case No. 2001-00141 based on a settlement, and the depreciation study filed in that case was based on plant in service as of December 31, 1999.

The AG opposed LG&E's increase, citing several problems with the new depreciation rates as well as problems with some of the net salvage values included in those rates. The AG argued that the net salvage incorporated into LG&E's proposed depreciation rates was not reflective of the actual net salvage experienced by LG&E, included future inflation in the estimates of future net salvage expense, and included retirement costs that LG&E likely would never incur and had no legal obligation to incur.[57] The AG contended that LG&E's depreciation proposal is not consistent with FERC Order No. 631, which requires separate accounting for the cost of removal

[56] Robinson Direct Testimony at 1 and 6.

[57] AG's Post-Hearing Brief at 15-20.

collected.[58] Lastly, the AG stated that the service lives used for several transmission and distribution plant accounts were incorrect.[59]

The AG recalculated the proposed depreciation rates by correcting the incorrect service lives and excluding the net salvage component. The AG proposed to recognize an annual net salvage allowance for LG&E, based on its actual 5-year average experience, in lieu of retaining the net salvage component in depreciation rates. The AG contended that the net salvage allowance is consistent with the requirements of FERC Order No. 631. Based on his recalculation, the AG proposed to reduce LG&E's test-year electric depreciation expense by $13,375,000.[60] The AG also suggested that $171,000,000 in overstated depreciation reserve should be returned to ratepayers over a 10-year period,[61] but he did not include this amount in his proposed depreciation adjustment.

LG&E disagreed with the AG's criticisms of the proposed depreciation rates. Concerning the treatment of net salvage, LG&E argued that the AG's approach would have the effect of deferring removal costs to the end of the life of the asset. This deferral would result in intergenerational inequities because customers who use the asset today are not paying the cost of removal today. Rather, those who are customers at the end of the asset life would have to pay the cost of removal.[62] Concerning the

[58] Majoros Depreciation Direct Testimony at 28-29 of 51.

[59] Id. at 43-45 of 51.

[60] Henkes Electric Direct Testimony, Schedule RJH-8.

[61] AG's Post-Hearing Brief at 23.

[62] Joint Post-Hearing Brief of LG&E and KU at 43.

AG's claim that separating the net salvage component from depreciation rates is required by FERC Order No. 631, LG&E noted that this claim is not supported by the language in the FERC Order.[63] LG&E also stated that the AG's proposed net salvage allowance was rarely accepted by regulatory agencies and that the AG's citations to previous Commission decisions in electric cooperative cases did not disclose the entire decision.[64] Lastly, LG&E stated that the AG's selection of the longest available service lives for certain transmission and distribution assets reflected a "results-oriented" approach to determining depreciation rates.[65]

Based on a comprehensive review of both depreciation studies, the Commission has concerns about each of them. For LG&E's study, the Commission has concerns about the inclusion of an inflation adjustment for the removal costs. Depreciation methods inherently recognize inflationary effects, since the depreciation rates are based upon comparisons of the original cost of the asset to the current cost of removal. This recognition assumes that future inflation rates will be similar to historical inflation rates. If it can be adequately demonstrated that future inflation rates will be different from the historical inflation rates, an inflation adjustment would be reasonable. However, to properly reflect this change in inflation rates, the effects of inflation currently incorporated in the accumulated depreciation would need to be removed. In response to a data request, LG&E provided a revision of its proposed depreciation rates that did not include adjustments based upon future estimates of inflation or other judgmental

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[63] Id. at 47.

[64] Id. at 43.

[65] Id. at 47-48.

factors.[66] After reviewing these rates, the Commission believes there are still problems related to the inflation adjustment that were contained in LG&E's initial depreciation study. Therefore, the Commission finds that LG&E's depreciation study should be rejected.

Concerning the AG's study, except for its recognition of LG&E's double counting of inflation, the Commission finds little justification for the AG's position and cannot accept his proposals as reasonable. The AG proposes that net salvage be based on a 5-year average. LG&E contends that the 5-year average is not appropriate because of intercompany transfers between LG&E and KU.[67] The Commission notes that the major reason for basing depreciation rates on an analysis of historical records is the expectation that the future is likely to follow trends that have occurred in the past. Therefore, it is not reasonable to use a 5-year average that contains unrepresentative data, but rather it would be more reasonable to use a longer time period in which such anomalies are likely to be averaged out.

The AG's claim that LG&E likely would never incur, or had no legal obligation to incur, the included retirement costs is irrelevant. The real question is whether it is reasonable to capitalize the cost of removal in order to recover those costs over the life of the investment. Capitalizing the cost of removal is a common practice and it has been accepted by this Commission for a number of years. The AG has not presented sufficient evidence in this case to persuade us to change this practice.

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[66] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 24(b), corrected in Robinson Rebuttal Testimony at 53 and Rebuttal Exhibit EMR-7.

[67] Robinson Rebuttal Testimony at 16.

The AG has also suggested that $171,000,000[68] of alleged over-stated depreciation reserve be amortized back to ratepayers over 10 years. What the AG seems to have not recognized is that when the remaining life technique is utilized, one of the early steps in the process of calculating remaining life rates is to calculate a theoretical reserve. The amount of deviation, whether positive or negative, of the actual reserves from the calculated theoretical reserves is then spread over the remaining life of the investment. Amortizing the deviation from the theoretical reserve over the remaining life of the investment is reasonable, and is normally incorporated into the depreciation rates. The performance of depreciation studies on a regular basis, including the determination of the current deviation from the theoretical depreciation reserve, is a reasonable alternative to an amortization over a fixed period of years.

The AG's extension of certain transmission and distribution asset service lives appears to be arbitrary rather than based on objective data. Depreciation estimates are just that - estimates. There are zones of reasonableness within which reasonable people will disagree. However, it is not reasonable to always select the service life that produces the lowest depreciation rates. Therefore, the Commission finds that the depreciation study submitted by the AG should also be rejected.

The Commission is especially concerned by the AG's interpretation of the provisions of FERC Order No. 631. As discussed above, FERC Order No. 631 generally adopted the provisions of SFAS No. 143. The AG's proposal to establish a

[68] The AG did not provide a schedule showing the determination of the $171,000,000 but instead references approximately 20 pages of detailed accounting printouts as the source of the figure. See Majoros ARO and SFAS 143 Direct Testimony at 21.

net salvage allowance relates to non-ARO assets, those assets for which LG&E does not have a legal retirement obligation. Concerning the removal costs associated with these non-ARO assets, FERC Order No. 631 states:

> 37. The purpose of this rule is to establish uniform accounting requirements for the recognition of liabilities for legal obligations associated with the retirement of tangible long-lived assets. The accounting for removal costs that do not qualify as legal retirement obligations falls outside the scope of this rule. The Commission is aware that there is an ongoing discussion in the accounting community as to whether the cost of removal should be considered as a component of depreciation. However, this issue is beyond the scope of this rule and we are not convinced that there is a need to fundamentally change accounting concepts at this time.
> 38. Instead we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated deprecation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. (emphasis added)

The language in FERC Order No. 631 clearly does not require the separation of the net salvage component from depreciation rates or the creation of a net salvage allowance as advocated by the AG. The requirement that separate subsidiary records be maintained is significantly different from requiring separation from depreciation rates.

Based on our findings to reject both of the depreciation studies submitted in this record, the Commission has normalized LG&E's test-year depreciation expense by applying its current depreciation rates to its utility plant in service as of September 30, 2003. This results in a reduction to LG&E's electric depreciation expense of $580,797.[69] The Commission further recognizes LG&E's willingness to file a new depreciation study by the earlier of its next general rate case or June 30, 2007, based

[69] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 16(a), page 4 of 7.

on plant in service as of a date no earlier than one year prior to the filing. This proposal is reasonable and will be accepted by the Commission.

Labor and Labor-Related Costs

LG&E proposed an increase in its electric labor and labor-related costs of $918,580. The proposed adjustment reflected the annualization of wages and salaries for the test year, the associated impact on payroll taxes, and an increase in the 401(k) company match.[70] When preparing the adjustment, LG&E assumed that Social Security and Medicare taxes would apply to 100 percent of the wage increase. It subsequently determined that at the end of year 2003, 98.72 percent of the wages did not exceed the Social Security wage limit, and it revised the increase proposed for the payroll taxes.[71]

The Commission believes that the labor adjustment should reflect the impact of the Social Security wage limit. The approach utilized by LG&E to determine the impact of this wage limit is reasonable. Based on this revised payroll tax adjustment, the Commission finds that LG&E's electric labor and labor-related costs should be increased by $917,916.[72]

[70] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.12.

[71] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 16(d)(3).

[72] The increase of $917,916 reflects an increase in wages of $837,128, plus a payroll tax increase of $63,376, plus an increase in the 401(k) company match of $17,412.

Pension and Post-Retirement Expenses

LG&E proposed to increase its test-year electric expense for pensions and post-retirement expenses by $2,755,476. LG&E claimed the adjustment was necessary to reflect the 2003 known and measurable expense changes determined by its actuary.

Initially, the AG did not propose a specific adjustment on pension and post-retirement expenses. However, in response to a data request, the AG recommended rejecting LG&E's adjustment and he revised his revenue calculation downward.[73] The AG opposed the pension and post-retirement expense adjustment proposed in the KU rate case, and stated in the LG&E rate case that consistency would dictate that KU and LG&E should be treated the same for rate-making purposes.[74]

The Commission notes that the AG submitted no testimony in this case on his recommendation to exclude LG&E's proposed adjustment for pension and post-retirement expenses, but instead relied on the testimony he filed in the KU rate case, Case No. 2003-00434. The Commission takes administrative notice of its findings and basis for rejecting the AG's position in that case, and affirms those findings in this proceeding. In that case, the AG argued that low interest rates and changes in the pension and post-retirement plan asset values contributed to the high level of expense that KU was seeking to recover. The Commission found that the AG had isolated only two of numerous factors that are considered in the very complex calculations required

[73] Response to the Commission Staff's First Data Request to the AG dated April 6, 2004, Item 5. The recognition of the exclusion of the proposed pension and post-retirement expense lowered the AG's recommended electric revenue increase from $12,141,000 to $9,366,000.

[74] Henkes Electric Direct Testimony at 54.

for pension and post-retirement benefit obligations and expenses. The Commission also cited the AG's lack of tangible evidence to support his assumptions and the absence of an explanation of how the circumstances relating to the pension adjustment he cited from Case No. 2000-00080 were applicable to KU's situation in that case. The Commission has in previous cases recognized the results of current actuarial studies in determining the reasonable level of pension and post-retirement expenses to include for rate-making purposes.[75] Here, LG&E has presented substantial evidence to support its adjustment and we find it persuasive. The Commission also notes that LG&E's pension and post-retirement plans are currently underfunded.[76] Therefore, the Commission finds that LG&E's proposal to increase its electric pension and post-retirement expense is reasonable and should be approved.

The Commission does have concerns about the underfunded status of LG&E's pension and post-retirement plans. LG&E should develop and implement a plan that eliminates the underfunding within a reasonable period of time. This plan should be filed with the Commission within one year from the date of this Order. In addition, LG&E should file progress reports describing the progress made in eliminating the underfunding of its pension and post-retirement plans. The progress reports should be filed every two years, and will be due with the filing of LG&E's annual financial report. The first progress report should be filed by March 31, 2007.

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[75] See Case No. 2000-00373, May 21, 2001 Order at 13-14 and Case No. 2001-00244, Adjustment of Rates of Fleming-Mason Energy Cooperative Corporation, final Order dated August 7, 2002 at 15-16.

[76] Post-Hearing Data Responses to Information Requested by the Commission Staff and the AG during Hearing held May 4-6, 2004, Item 9.

Storm Damage Expense

LG&E proposed to normalize its storm damage expense by using a 10-year historic average adjusted for inflation. LG&E stated that this was the same methodology utilized by the Commission in Case No. 1990-00158. The normalization resulted in an increase of $70,492 over the test-year actual expense.

While the Commission agrees with the methodology used by LG&E, the inflation factor was not determined in a manner consistent with the approach used by the Commission in previous cases. The inflation factor previously used by the Commission is based upon the Consumer Price Index – All Urban Consumers ("CPI-U").[77] To determine the inflation factor for a particular year, the Commission divides the CPI-U for the base year by the CPI-U for the particular year.[78] The Commission has recalculated the storm damage expense adjustment using the inflation factor approach previously utilized, and determined that LG&E's storm damage expense should be increased by $83,765.

Rate Case Expense

When LG&E filed its electric rate case, it estimated that the total cost of the case would be $1,000,739. LG&E requested the recovery of its rate case expenses over a 3-year period, noting that this approach was consistent with previous Commission

[77] LG&E provided the CPI-U for the 10-year period in its response to the Commission Staff's Second Data Request dated February 3, 2004, Item 16(f).

[78] In this case, the base year is 2003. The calculation of the inflation factor for 2000 would take the CPI-U for 2003 divided by the CPI-U for 2000, in this example, 184.0 divided by 172.2. This results in an inflation factor for 2000 of 1.0685.

decisions. Based on the estimated rate case expenses, LG&E included a rate case expense of $333,580.

While the AG agreed with the approach of amortizing rate case expenses over 3 years, he questioned the level of estimated expenses and argued that the Commission should only allow the actual amount of prudently incurred rate case expenses. The AG calculated a rate case expense of $108,000, but acknowledged that this amount should be adjusted as LG&E documents additional, prudently incurred rate case expenses.[79] In its rebuttal testimony, LG&E agreed with the AG that this expense adjustment should be based only on actual expenses.[80] LG&E's latest update of actual electric rate case expenses total $687,778.[81]

The Commission agrees with both LG&E and the AG that only the actual, reasonable rate case expenses incurred in presenting this case should be recovered over a 3-year period. However, a review of LG&E's invoices for legal services reveals that the descriptions of services provided have been redacted for several line items on the basis that the information was protected by the attorney-client privilege.[82] LG&E later provided an affidavit of its counsel to affirm that the redacted legal services were

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[79] Henkes Electric Direct Testimony at 41-43. The $108,000 reflects the first year of the 3-year amortization of total actual rate case expenses.

[80] Scott Rebuttal Testimony at 5-6.

[81] LG&E Updates of the Responses to the Commission Staff's First Data Request dated December 19, 2003, Items 43, 44, and 57, filed May 28, 2004. LG&E has provided supporting documentation for all rate case expenses reported throughout this proceeding.

[82] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 1, pages 11, 17, 20-21, and 24-28 of 160.

associated with this electric rate case.[83] The Commission recognizes and appreciates LG&E's right to assert its privilege to not disclose the nature of certain legal work performed by its attorneys. However, when a utility seeks to recover an expenditure in its rates, the Commission is obligated to review the nature of that expenditure to verify that it is just and reasonable. In this instance, we are unable to determine from the evidence of record the nature of certain legal services performed and whether those services were related to this rate case. Therefore, the Commission finds that $18,929 should be disallowed from the latest reported actual electric rate case expense. The Commission has calculated that the first year of a 3-year amortization of the actual electric rate case expenses is $222,950 and electric operating expenses have been increased by this amount.

Injuries and Damages

LG&E proposed to adjust its test-year expense for injuries and damages based on normalizing the actual expenses for a 5-year period, adjusted for inflation. LG&E used the same methodology that it proposed for adjusting its storm damage expense, except it excluded its test-year expenses and based the adjustment on the past 5 years rather than 10 years. LG&E determined its electric injuries and damages expense needed to be increased by $501,449. LG&E subsequently stated that a 10-year historical period would result in a better representation of normal expenses, and it recalculated the adjustment for injuries and damages using the same methodology as it

[83] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 3(d).

did for storm damage expense. The recalculation produced an increase in expense of $1,210,001.[84]

The AG agreed with LG&E's adjustment based on a 5-year period adjusted for inflation, but recommended including the test-year amount in calculating the 5-year average. The AG contended that including the test-year amount would result in a normalized expense based on the most recent actual data. The AG determined the increase in injuries and damages should be $430,000.[85]

The Commission finds it reasonable to calculate this adjustment using the same methodology used to determine the storm damage expense adjustment. Like storm damages, the injuries and damages expenses can fluctuate significantly from year to year. The 10-year historic average, adjusted for inflation, should produce a more reasonable ongoing level of expense. The recalculated adjustment in LG&E's rebuttal testimony used the same inflation factors as LG&E used in its storm damage expense adjustment. As discussed previously, the inflation factors were not determined in a manner consistent with previous Commission decisions. The Commission has calculated the 10-year historic average for injuries and damages, adjusted for inflation. Based upon this calculation, the Commission finds that LG&E's electric injuries and damages expense should be increased by $1,242,436.

Information Technology Staff Reduction

In October 2003, LG&E Energy Services, Inc. reduced its Information Technology staff by 27 employees. LG&E proposed an electric operating expense

[84] Scott Rebuttal Testimony at 6-7 and VLS Rebuttal Exhibit 2, page 1 of 2.

[85] Henkes Electric Direct Testimony, Schedule RJH-11, line 3.

reduction of $431,834, to reflect the savings from this staff reduction, offset by the first year of a 3-year amortization of the costs to achieve the reduction. LG&E determined the savings from the reduction based on payroll expense, payroll tax, and the 401(k) plan match.[86]

The AG agreed with the adjustment, but noted that LG&E had not recognized savings for the Team Incentive Awards ("TIA") and other employee benefits such as pension, post-retirement benefits, long-term disability, and various insurance coverages.[87] After including these additional employee savings, the AG increased LG&E's reduction from $431,834 to $674,834.[88]

The Commission agrees with the AG that the additional employee savings should be recognized in determining the employee reduction adjustment. The Commission finds that LG&E's electric operating expenses should be reduced by $673,403.[89]

Write-off of Obsolete Inventory

During the test year, LG&E wrote-off obsolete parts inventory totaling $2,060,448. LG&E proposed to defer this write-off and to amortize the cost over a 3-year period. LG&E argued that the costs incurred to purchase the inventory were

[86] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.26.

[87] Henkes Electric Direct Testimony at 45-46.

[88] Id., Schedule RJH-12. The AG determined the incremental increase in the reduction to be $243,000, which reflects 79 percent of the total additional employee savings of $306,990.

[89] The adjustment was recalculated using the format shown in Rives Exhibit 1, Schedule 1.26 and increasing line 7 by the additional total expense savings of $306,990. The 79 percent allocation factor for electric operations was applied to the net cost reduction to arrive at the $673,403.

prudent business expenditures and that allowing deferral and amortization of the costs would establish a representative, ongoing level of expenses. LG&E stated that this accounting treatment is consistent with the Commission's decision in Case No. 10064[90] concerning the early retirement of scrubbers and the abandonment of underground gas storage fields. Including the first year amortization, LG&E proposed an electric net operating expense reduction of $1,373,632.

The AG opposed this adjustment, contending that the write-off of obsolete inventory is a non-recurring event that should not be reversed by the means of a deferral and amortized through rates. The AG also argued that LG&E's proposed treatment of this adjustment was not consistent with LG&E's proposed adjustment for the Cane Run repair refund.[91]

The Commission is not persuaded by LG&E's claim that this proposed deferral and amortization is comparable with the early retirement and abandonment of utility plant addressed in Case No. 10064. The treatment prescribed in Case No. 10064 for the early retirement and abandonment of utility plant was the determination that those events constituted extraordinary property losses.[92] LG&E has provided no evidence in this proceeding to support the contention that the write-off of obsolete parts inventory constituted an extraordinary property loss. Consequently, it is not appropriate to defer this expense incurred in the test year and to amortize it over a period of years.

[90] Case No. 10064, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company.

[91] Henkes Electric Direct Testimony at 46-47.

[92] Case No. 10064, July 1, 1988 Order at 17.

The Commission does recognize that a utility will experience from time to time the write-off of obsolete inventory. The amount written off will vary from year to year based on the circumstances surrounding the inventory becoming obsolete. We agree with LG&E that an objective of rate-making is to include reasonable, representative, ongoing levels of expenses that will be recovered through rates. The Commission finds that it is reasonable to adjust LG&E's expenses to include one-third of the test-year write-off of obsolete parts inventory. This amount will be included as a reasonable, representative, ongoing level of expense, and not as the amortization of a deferred cost. Therefore, the Commission finds that one-third of the test-year write-off of obsolete inventory should remain in electric operating expenses, thus resulting in a reduction of electric operating expenses of $1,373,632.

Write-off of Carbide Lime

During the test year, LG&E wrote-off the payment made to secure a supply of carbide lime for pollution control facilities at its Cane Run generating station. The supplier of the carbide lime had gone bankrupt, and the deposit on the contract was written off. LG&E proposed to reverse the write-off, to create a deferred debit, and to amortize the deferral over a 3-year period. After reflecting the first year of the 3-year amortization, LG&E proposed to reduce its electric operating expenses by $1,416,711. LG&E argued that while the cost was not expected to be of a recurring nature, it was prudently incurred, and incurred to benefit customers by securing material needed in the scrubber process. LG&E further argued that it should have the opportunity to recover this investment regardless of the frequency of write-offs.[93]

[93] Joint Post-Hearing Brief of LG&E and KU at 70.

The AG opposed the adjustment, arguing that the write-off was a non-recurring event that did not reflect a representative level of annual expense for rate-making purposes.[94]

Generally, the Commission has not permitted the deferral and future recovery of non-recurring costs that have been expensed in the test year. The Commission has made exceptions to this position when it has been demonstrated that consideration of other factors, such as the material nature of the costs, the future benefit of the costs to ratepayers and shareholders, and the proper matching of future benefits with the costs, has warranted different treatment.

The Commission is not persuaded by the arguments of LG&E. While LG&E stated that the carbide lime was needed for its scrubber process at the Cane Run generating station, the Commission notes that after October 2002, LG&E no longer carried an inventory of carbide lime.[95] LG&E has not explained why ratepayers should be required to pay for an investment in inventory that no longer exists on LG&E's books. In addition, LG&E has failed to demonstrate what future benefit to ratepayers or shareholders exists that warrants the deferral and amortization of this non-recurring expense.

Based on these findings, the Commission agrees with the AG that LG&E's proposal to defer and amortize its write-off of carbide lime should be rejected. The Commission has reduced electric operating expenses by $2,125,000. In addition, since

[94] AG's Post-Hearing Brief at 11.

[95] Response to the Commission Staff's Second Data Request dated February 3, 2004, Item 15(d)(3) and 15(d)(4), page 2 of 3.

LG&E currently does not maintain an inventory of carbide lime, and its contract for the supply of carbide lime has been terminated, the Commission will accept the AG's adjustment to LG&E's pro forma rate base to remove the carbide lime from the 13-month average of materials and supplies. This adjustment is shown in Appendix D.

Promotional Expenses

The AG proposed to reduce electric operating expenses by $90,450 to remove promotional expenses. The proposed adjustment reflected the balances in Account Nos. 909001, 909002, 912001, and 912005. The AG argued that the promotional expenses have not been included for rate-making purposes in previous Commission decisions and that the expenses failed to provide the "material benefit," as defined in 807 KAR 5:016,[96] necessary for their inclusion in rates.

LG&E disagreed with the portion of the AG's proposed adjustment that related to Account Nos. 912001 and 912005. LG&E argued that the expenses in Account No. 912001 related to economic development and did produce the "material benefit" envisioned in 807 KAR 5:016. LG&E noted that the commitments agreed to by LG&E and other parties in Case No. 2001-00104[97] required it to maintain a proactive stance on developing economic opportunities and supporting economic development. LG&E also argued that the expenses in Account No. 912005 related to customer satisfaction surveys and utility industry research that helps LG&E provide better customer service.

[96] Henkes Electric Direct Testimony at 39-41.

[97] Case No. 2001-00104, Joint Application for Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company in Accordance with E.ON AG's Planned Acquisition of Powergen PLC.

The AG disagreed with the reasons offered by LG&E in support of including Account Nos. 912001 and 912005 for rate-making purposes.[98]

The Commission has reviewed the accounts included in the AG's proposed adjustment. Concerning Account No. 909001, we do not agree with the AG's proposal to exclude the entire balance of this account. A significant portion of the account balance has been identified as conservation and safety advertising and customer information.[99] Conservation and safety advertising and customer information are considered under 807 KAR 5:016 to provide material benefits to ratepayers and are permitted to be included for rate-making purposes. Therefore, the amounts identified as conservation and safety advertising and customer information will not be excluded for rate-making purposes. Concerning Account No. 909002, the Commission agrees with the AG and will remove this expense balance for rate-making purposes.

Concerning Account Nos. 912001 and 912005, the Commission is not persuaded by LG&E's arguments. Account No. 912, Demonstrating and Selling Expenses, is defined as "the cost of labor, materials used and expenses incurred in promotional, demonstrating, and selling activities, except by merchandising, the object of which is to promote or retain the use of utility services by present and prospective customers."[100] Under the provisions of 807 KAR 5:016, Section 4(a), promotional advertising is stated as not producing a material benefit and such costs are expressly disallowed for rate-making purposes. Promotional advertising is defined in 807 KAR 5:016 as "any

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[98] AG's Post-Hearing Brief at 8.

[99] Response to the AG's First Data Request dated February 3, 2004, Item 229.

[100] 18 CFR 101 at 393. The USoA for electric utilities is codified as 18 CFR 101.

advertising for the purpose of encouraging any person to select or use the service or additional service of an energy utility, or the selection or installation of any appliance or equipment designed to use such utility's service."[101] The definition of Account No. 912 clearly falls within the definition of promotional advertising, which cannot be included for rate-making purposes.

In addition, the commitments in Case No. 2001-00104 do not unconditionally justify the inclusion of expenses LG&E contends are related to economic development. Commitment No. 43 states, as follows:

> 43. E.ON and PowerGen commit to maintaining LG&E's and KU's pro-active stance on developing economic opportunities in Kentucky and supporting economic development, and social and charitable activities, throughout LG&E's and KU's service territories.[102]

While the commitment requires LG&E to continue supporting economic development, nothing in the commitment addresses the recovery of the expenses which are the subject of the commitment.

The Commission will take this opportunity to reaffirm its support of economic development activities. However, in this proceeding, LG&E has not provided sufficient evidence to demonstrate that the expenses in Account No. 912001 are actually related to economic development. Therefore, the Commission finds that LG&E's electric operating expenses should be reduced by $79,997.

[101] 807 KAR 5:016, Section 4(b).

[102] Case No. 2001-00104, final Order dated August 6, 2001, Appendix A at 11.

Miscellaneous Expenses

The AG proposed an adjustment to reduce miscellaneous expenses by $218,361.[103] The AG's proposed adjustment was comprised of three items. First, he removed charitable contributions that LG&E had recorded in accounts other than Account No. 426. Second, he removed 50 percent of test-year electric operating expenses associated with employee gifts, award banquets, parties, and other social events based on his understanding of previous Commission decisions that these types of employee expenses are not normally included for rate-making purposes. Lastly, he recommended that 72.16 percent of LG&E's dues paid to the Edison Electric Institute ("EEI") should be disallowed, an amount of $141,001, based on a claim that the portion of the EEI dues dedicated to legislative advocacy, regulatory advocacy, legislative and regulatory policy research, institutional advertising and marketing, and public relations produced no benefit to ratepayers and should be borne by LG&E's stockholders.[104]

LG&E agreed that the charitable contributions that had been recorded in error in accounts other than Account No. 426 should be removed for rate-making purposes.[105] LG&E strongly disagreed with the AG's adjustment to remove the expense of employee gifts, award banquets, and social expenses, arguing that those expenses were prudent and reasonable and should be charged to ratepayers because they reward employees

[103] Henkes Electric Direct Testimony, Schedule RJH-15. The AG also included on this schedule an adjustment to reflect the full year impact of the environmental surcharge roll-in. That adjustment was addressed previously in this Order.

[104] Id. at 49-50.

[105] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 34.

in connection with LG&E's safety programs and professional achievements and accomplishments. LG&E further argued that these expenses contribute to the morale of employees and provide incentives to encourage high levels of performance.[106] Concerning the EEI dues, LG&E agreed that the portion associated with legislative advocacy and public relations should be excluded for rate-making purposes, but the portion associated with the other activities were reasonable to include for rate-making purposes. LG&E proposed that 31.55 percent of its EEI dues, or $61,649, should be excluded.[107]

The Commission agrees that the charitable contributions should be excluded for rate-making purposes. The AG assumed that 80 percent of the total contributions were applicable to LG&E's electric operations. Based on LG&E's 2003 Common Utility Study, the Commission has concluded that 87 percent is the appropriate level to allocate to LG&E's electric operations. Therefore, the Commission finds that electric miscellaneous expenses should be reduced by $19,528 for this item.

The Commission agrees with the AG that the expenses for employee gifts, award banquets, and social events should be excluded for rate-making purposes. In previous cases,[108] the Commission has not included these types of costs when determining

[106] Scott Rebuttal Testimony at 8.

[107] Post-Hearing Data Responses to Information Requested by the Commission Staff and the AG during Hearing held May 4-6, 2004, Item 11.

[108] See Case No. 1990-00041, An Adjustment of Gas and Electric Rates of The Union Light, Heat and Power Company, final Order dated October 2, 1990 at 28-29; Case No. 1997-00066, An Adjustment of General Rates of Delta Natural Gas Company, Inc., final Order dated May 1, 1998 at 16-17; and Case No. 2001-00244, August 7, 2002 Order at 27-28.

rates, and LG&E has not provided adequate justification to support a different treatment. In addition, the Commission notes that emphasis on safety and incentives to encourage employee performance are incorporated into LG&E's TIA program. LG&E did agree that there was some overlap between the TIA program and the purpose for these expenses.[109] However, while agreeing with the AG that these expenses should be excluded for rate-making purposes, we find there is no basis for the AG's proposal to exclude only 50 percent of the test-year level. Therefore, the Commission finds that 100 percent should be excluded, thereby reducing electric miscellaneous expense by $118,805.

The Commission supports LG&E's efforts to reinforce the need for safety among their employees and encourages LG&E to develop appropriate safety programs. In future rate cases, the Commission will reconsider the treatment of safety-related awards to the extent that LG&E can provide adequate documentation to show that these awards and other activities are integral components of a formal safety program.

Concerning the EEI dues, the Commission has reviewed the description of the various activities funded by the EEI dues,[110] and finds that the portion of the dues associated with legislative advocacy, regulatory advocacy, and public relations should be excluded for rate-making purposes. The description of regulatory advocacy appears to be a form of lobbying activity, which the Commission has not included for rate-making purposes in previous cases. These three categories account for 45.35 percent of the

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[109] T.E., Volume II, May 5, 2004, at 176.

[110] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 44.

EEI dues.[111] Applying the 45.35 percent exclusion to the test-year EEI dues results in a reduction of $88,614.[112]

During the test year, LG&E had allocated $15,097 in expenses associated with EEI conferences to its gas operations. Based on a review of the conference descriptions, we cannot accept LG&E's contention that a portion of these conference expenses should be allocated to gas operations.[113] The Commission finds that LG&E's allocation of these EEI conference expenses should be reversed, with all EEI conference expenses charged to LG&E's electric operations. This results in an increase in electric operating expenses of $15,097. The Commission further finds that, unless LG&E can adequately document otherwise, all expenses associated with EEI activities should be charged to electric operations.

Based on these conclusions, the Commission has reduced electric miscellaneous expenses by $211,850.

Kentucky Income Tax Rate

LG&E determined that its federal and Kentucky income tax expense would be reduced by $27,540,380, based upon its proposed adjustments to electric revenues and

[111] Post-Hearing Data Responses to Information Requested by the Commission Staff and the AG during Hearing held May 4-6, 2004, Item 11, page 2 of 3.

[112] EEI dues of $195,401 times 45.35 percent equals $88,614.

[113] Response to the AG's First Data Request dated February 3, 2004, Item 313. The largest single conference expense allocated to gas operations, in the amount of $13,194, was related to the Utility Air Regulatory Group, which provided Clean Air Act representation and monitoring of regulatory issues to electric utilities before the Environmental Protection Agency and the federal courts. LG&E agreed that allocating this conference expense to gas operations was in error, See T.E., Volume II, May 5, 2004, at 175.

expenses. LG&E's calculation reflected the use of the statutory federal income tax rate of 35 percent and the statutory Kentucky income tax rate of 8.25 percent.

The AG proposed that LG&E's effective Kentucky income tax rate for tax year 2002 of 7.87 percent should be used in all income tax and income tax-related calculations. The effective Kentucky income tax rate results from LG&E's ability to file a consolidated Kentucky corporate income tax return. The AG noted that the Commission adopted the use of the effective Kentucky income tax rate for The Union Light, Heat and Power Company's ("ULH&P") last rate case on a trial basis. The AG stated that the Commission's expressed concern in the ULH&P case about using the effective Kentucky income tax rate should not be a concern here since LG&E's effective Kentucky income tax rates over the last 4 years were nearly constant. The AG argued that the use of the effective tax rate should be extended to LG&E so its ratepayers can receive the benefit of the reduction in income taxes resulting from the filing of consolidated tax returns. However, the AG noted that in addition to applying the effective Kentucky income tax rate to the adjustments accepted in this proceeding, it would be necessary to adjust the level of income taxes included in the determination of test-year-actual net operating income, since the taxes would still be based upon the statutory Kentucky income tax rate.[114]

LG&E opposed this recommendation, noting that the Commission has always used the statutory tax rate and that consistent treatment should be afforded to LG&E. LG&E argued that the effective tax rate reflects the impacts of credits and apportionment adjustments from out-of-state activities, which could change in the future.

[114] AG's Post-Hearing Brief at 4-5.

LG&E stated that the use of the effective tax rate would ignore the fact that it pays Indiana tax on a portion of its off-system sales. If the effective tax rate is to be used, LG&E reasoned, the Indiana tax of 8.07 percent should be included in the determination of the effective tax rate.[115]

In Case No. 2001-00092,[116] ULH&P proposed to use its effective Kentucky income tax rate in the calculation of all income tax and income tax-related adjustments. Kentucky income tax law permits corporations such as LG&E to file consolidated Kentucky corporation income tax returns.[117] Under this approach, the E.ON US Investment Corporation's net taxable income is apportioned to Kentucky based on a weighted property, payroll, and receipts factor. The effective Kentucky income tax rate is a result of this apportionment of income plus the inclusion of companies that would not have filed a Kentucky return, except for the fact that they were members of the E.ON US Investment Corporation consolidated group.

The Commission in not persuaded by the AG's arguments. Case No. 2001-00092 was a gas operations only rate case, and there was no issue related to out-of-state taxation of off-system sales, and, of particular note, ULH&P expressly requested the use of the effective income tax rate. Here, LG&E expressly opposes using the effective tax rate. We do agree with the AG's position that if the effective income tax rate is utilized, there would have to be an adjustment to the test-year-actual income tax

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[115] Rives Rebuttal Testimony at 9-10.

[116] Case No. 2001-00092, An Adjustment of Gas Rates of The Union Light, Heat and Power Company.

[117] See KRS 141.200 and 103 KAR 16:200.

expense shown in LG&E's operating statement. The existence of the Indiana tax on off-system sales would have to be addressed in such an adjustment, and the record in this proceeding does not contain sufficient information to accurately do so. Therefore, the Commission finds that the statutory Kentucky income tax rate should be utilized for all income tax and income tax-related adjustments in this rate case. However, the Commission notes that it will be reviewing the use of the effective tax rate in ULH&P's next rate case. In LG&E's next rate case, it should address in detail the use of the effective tax rate for rate-making purposes.

Based upon these findings and the Commission's determination of the electric revenue and expense adjustments, the Commission has reduced LG&E's electric income tax expense by $23,794,268.

Interest Synchronization

LG&E originally proposed to reduce its interest expense by $98,001, which resulted in an increase to income tax expense of $39,556.[118] LG&E stated that it followed the methodology used by the Commission in Case No. 2000-00080. LG&E multiplied its proposed adjusted electric capitalization by its proposed weighted average cost of debt to determine its normalized interest expense. The normalized interest expense was then compared to the test-year actual interest expense per LG&E's books. During the proceeding, LG&E discovered several errors in its calculations. The result of LG&E's corrections was an increase in its interest expense of $1,008,247, and a corresponding decrease in income tax expense of $406,954.[119]

[118] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.37.

[119] Rives Rebuttal Testimony, SBR Rebuttal Exhibit 2.

The AG agreed with LG&E's methodology and recognized the corrections identified by LG&E. The AG calculated his adjustment using a composite federal and Kentucky income tax rate that reflects the effective Kentucky income tax rate, rather than the statutory tax rate. The AG determined that LG&E's income tax expense should be decreased by $403,000.[120]

The Commission has recalculated the interest synchronization adjustment, reflecting the debt components of LG&E's electric capitalization, the corresponding interest cost rates found reasonable in this Order, and the statutory Kentucky income tax rate. The Commission has determined that LG&E's electric interest expense should increase $563,647, resulting in a reduction in income taxes of $227,502.

Pro Forma Net Operating Income Summary

After consideration of all pro forma adjustments and applicable income taxes, the adjusted net operating income for LG&E's electric operations is as follows:

Operating Revenues	$726,815,085
Operating Expenses	653,002,752
Adjusted Electric Net Operating Income	$ 73,812,333

RATE OF RETURN

Capital Structure

LG&E proposed an adjusted test-year-end electric capital structure containing 40.74 percent long-term debt, 3.84 percent short-term debt, 3.82 percent accounts receivable securitization, 3.60 percent preferred stock, and 48.00 percent common

[120] Henkes Electric Direct Testimony, Schedule RJH-5.

equity.[121] As discussed previously in this Order, LG&E has allocated several adjustments to its capitalization on a pro rata basis or to common equity only as it determined appropriate.[122] During the proceeding, LG&E stated it had considered the Commission's policy of recognizing the impact on capital cost and capital structure of significant post-test-year issues of debt or equity. LG&E has updated its capital structure to reflect post-test-year changes, with the last update reflecting financial information as of March 31, 2004.[123] Using this latest financial information, LG&E determined its capital structure as 41.91 percent long-term debt, 5.01 percent short-term debt, 3.58 percent preferred stock, and 49.50 percent common equity. This updated capital structure did not reflect an adjustment for LG&E's minimum pension liability as of December 31, 2003. In March 2004, LG&E applied the accounting decision announced by FERC concerning the creation of a regulatory asset to reverse the impact of the minimum pension liability.

The AG proposed an adjusted test-year-end electric capital structure for LG&E containing 41.45 percent long-term debt, 3.90 percent short-term debt, 3.89 percent accounts receivable securitization, 3.66 percent preferred stock, and 47.10 percent

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[121] Rives Direct Testimony, Rives Exhibit 2, page 1 of 2.

[122] LG&E allocated adjustments for JDIC, the removal of 25 percent of inventories associated with Trimble County Unit 1, its equity investment in OVEC, the removal of reimbursed capital invested to repair combustion turbines at the E. W. Brown Generating Station, and the removal of its Post-1995 environmental compliance plan investments on a pro rata basis to all components of capitalization. The proposed adjustment for the minimum pension liability to Other Comprehensive Income was allocated to common equity only.

[123] Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 10. LG&E's update that reflected financial information as of March 31, 2004 was filed with the Commission on April 29, 2004.

common equity.[124] The only difference from LG&E's proposal was that the AG rejected LG&E's treatment of the minimum pension liability. The AG did not oppose LG&E updating its capital structure, but the AG did state that the capital structure ratios could be updated beyond the test year only if the changes were minor so that any change in the company's financial risk would also be minor. Changes beyond the test year that affected the financial risk should not be allowed, according to the AG.[125]

In December 2000, the Commission approved LG&E's 3-year pilot accounts receivable securization program in Case No. 2000-00490.[126] At the end of the pilot period, LG&E decided not to seek a continuation of the program, and consistent with the decision in Case No. 2000-00490, the accounts receivable securization program was terminated on January 16, 2004. LG&E replaced the funding provided by the accounts receivable securization program with a mix of short-term and long-term debt from Fidelia, Inc. ("Fidelia").[127]

As correctly noted by LG&E, the Commission in previous cases has recognized the impact on the capital structure of significant post-test-year issues of debt or equity in order to determine the appropriate capital structure. Consequently, the Commission finds it reasonable to recognize the termination of the accounts receivable securization

[124] Henkes Electric Direct Testimony, Schedule RJH-2.

[125] Weaver Testimony at 77-78.

[126] Case No. 2000-00490, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for an Order Approving the Transfer of Certain Financial Assets, final Order dated December 13, 2000.

[127] Fidelia is owned by E.ON North America Inc. and E.ON US Holding GmbH, which are subsidiaries of E.ON. See Response to the Commission Staff's First Data Request dated December 19, 2003, Item 2.

program and the issuance of debt from Fidelia in the determination of LG&E's capital structure.

However, we do not agree with LG&E's proposal to simply use the updated capital structure as of March 31, 2004. Unlike its debt, LG&E did not issue any new shares of common stock. The March 31, 2004 financial information reflects the current level of net income from operations in Retained Earnings. As discussed previously in this Order, the Commission has recognized the adjustment to test-year-end common equity for the minimum pension liability. That minimum pension liability reflected the determination made at December 31, 2002. The application of the FERC accounting decision and creation of the regulatory asset reflected in the March 31, 2004 financial information reflect a minimum pension liability determined as of December 31, 2003. If the Commission were to use the capital structure based on the March 31, 2004 financial information, there would be a mismatch related to the minimum pension liability. The Commission's decision to allow the reversal of the December 31, 2002 minimum pension liability to common equity is the appropriate means of handling this issue, and it should be recognized in the capital structure.

As shown in Appendix E, the Commission finds LG&E's electric capital structure is as follows:

	Percent
Long-Term Debt	42.58
Short-Term Debt	5.17
Preferred Stock	3.65
Common Equity	48.60
Total Electric Capital Structure	100.00

Cost of Debt and Preferred Stock

LG&E proposed a cost of long-term debt of 3.77 percent, short-term debt of 1.06 percent, accounts receivable securization of 1.39 percent, and preferred stock of 2.51 percent.[128] As noted previously, LG&E filed updated financial information as of March 31, 2004 that included updated cost rates. Based on this updated information, LG&E's cost of long-term debt is 3.57 percent, short-term debt is 1.54 percent, and preferred stock is 2.59 percent.[129]

The AG used LG&E's costs of debt and preferred stock as filed in its application. The AG agreed that if interest rates or other capital cost rates change, such changes should be used to determine the rate of return so that LG&E will have a reasonable opportunity to earn its allowed return.[130]

The Commission finds it appropriate to recognize the cost rates for debt and preferred stock as of March 31, 2004 when determining the overall cost of capital for LG&E's electric operations. Updates to LG&E's debt and preferred stock cost rates constitute known and measurable adjustments and using these updates, rather than the test-year-end cost rates, is more representative of the period in which the rates established in this Order will be in effect. These cost rates will be applied to the electric capital structure determined herein. Therefore, the Commission finds the cost of long-

[128] Rives Direct Testimony, Rives Exhibit 2, page 1 of 2.

[129] Updated Monthly Response to the Commission Staff's First Data Request dated December 19, 2003, Item 43, filed April 29, 2004.

[130] Weaver Testimony at 77.

term debt to be 3.57 percent, short-term debt to be 1.54 percent, and preferred stock to be 2.59 percent.

Return on Equity

LG&E estimated its required return on equity ("ROE") using four methods: the capital asset pricing model ("CAPM"), the discounted cash flow method ("DCF"), two risk premium analyses, and a comparable earning approach.[131] The CAPM analysis includes an adjustment of 60 basis points in order to recognize a size premium for some of the low- and mid-capitalization companies in its comparison group. LG&E explained that it employed multiple methods in determining its cost of equity because of potential measurement errors in the models as a result of industry changes, such as merger activity and price volatility.

LG&E performed separate analyses on its electric and gas operations; however, with the settlement of the gas-related issues, LG&E withdrew the ROE testimony for its gas operations. Based on the results of the four methods, LG&E recommends an ROE range for its electric operations of 10.75 to 11.25 percent.[132] LG&E recommends awarding the upper end of the range, 11.25 percent, in order to recognize its efficient operations and the current uncertain business climate for utilities.[133]

LG&E employed a proxy group in its analysis, consisting of electric utility companies similar in risk to its electric operations. LG&E proposed the use of proxy companies because, as a subsidiary of LG&E Energy, it is not publicly traded. The

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[131] Rosenberg Direct Testimony at 2.

[132] Id.

[133] Id. at 4.

companies were selected from the Electric Utility category of *The Value Line Investment Survey*. The selected companies had to have overall senior bond ratings of Aa/A from Moody's Investor Service and AA/A from Standard & Poor's ("S&P") rating service and could not be currently involved in major merger activity. Companies were also excluded if they had significant unregulated operations, if they did not pay a dividend or if they expected to cut their dividend.

As part of its analysis, LG&E provided a discussion of the role that ROE plays in how the financial community regards a utility company. LG&E states that accounting scandals, federal and state investigations, and other negative fallout from the collapse of Enron have shaken investor confidence in the energy industry. The result is more intense scrutiny of companies and a scarcity of financing at a time when many energy companies need to refinance billions of dollars of debt. At the time of its application, LG&E stated that S&P had reported 41 utility issuer credit rating downgrades, as compared to only eight upgrades during 2003. Moody's had downgraded roughly a third of the utilities it follows, as compared to the 10 percent annual average downgrades it had issued over the past 19 years. LG&E argued that these actions indicate less tolerance for financial weakness in a utility and that they have increased the cost of financing to weaker companies. In support of its argument, LG&E provided several citations from S&P publications that described the authorized returns for the regulated electric industry as insufficient and discussed the importance of profit potential and earning power in both credit protection and a company's ability to withstand business adversity.[134]

[134] Id. at 7-9.

The AG criticized LG&E's ROE estimates on several grounds. The AG disagreed with several of the methodologies and inputs used by LG&E and with LG&E's small cap adjustment in the CAPM model. Two points which the AG identified as "fatal errors" were: (1) LG&E should not have used the Consumer Price Index ("CPI") when working with the Gross Domestic Product ("GDP") data; and (2) LG&E should have multiplied projected GDP growth and projected inflation growth instead of adding.[135] The AG argues that the small cap adjustment is already in the market prices of the mid- and low-capitalization companies used in the analysis and he concludes that LG&E's flawed analysis overstates its required cost of equity.

The AG estimated LG&E's required ROE using three methods: the CAPM, the bond-yield-plus-risk premium approach, and two versions of the DCF model.[136] The analyses were performed separately for LG&E's electric operations. Based on the results of these methods, the AG determined an ROE range of 9.75 to 10.25 percent for LG&E's electric operations, recommending that the Commission award 10.00 percent, the mid-point of the range.[137] During the hearing, the AG's witness stated that he would change his recommendation from 10.00 percent to 10.25 percent if LG&E's ESM is eliminated as proposed in the settlement of this issue.[138]

The AG employed a proxy group in his analysis, consisting of utility companies classified as electric utilities by *Value Line*. The AG eliminated companies with a

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[135] Weaver Testimony at 8.

[136] Id. at 32.

[137] Id. at 75.

[138] T.E., Volume III, May 6, 2004, at 177-179.

Financial Strength Rating below B, that *Value Line* did not recommend to investors, that had recently sold or purchased major assets, divested the majority of their generation plant, were involved in merger activity, or had a short operating history. The AG excluded Hawaiian Electric because it is not interconnected and also excluded any companies with a heavy reliance on hydro, nuclear or purchased power. Finally, the AG did not include any companies whose electric revenues as a percentage of total revenues were too dissimilar to that of LG&E.

The AG supported his analysis with a discussion of the economic conditions that would affect the ROE he recommended. He reviewed the GDP, inflation rates, interest rates and leading economic indicators. The AG believes that the GDP growth rate is within a range ideal for investment growth, that inflation is expected to continue to be low, and that interest rates are expected to be stable yet gradually increasing over the next 4 years. The AG concluded that the cost of equity for electric utilities would slowly increase over the near-term future. In fact, he made an adjustment in his DCF model to increase the results by 95 basis points to recognize an expected increase in interest rates.

On rebuttal, LG&E questioned the AG's recommended range since it differed by 50 to 100 basis points from the range recommended by this same witness in the ESM case, which was consolidated into this rate case. In his ESM testimony, the AG recommended a range of 10.25 to 11.25 percent, just 3 months prior to filing rate case testimony in which he recommends 9.75 to 10.25 percent.[139] In response to questions about how LG&E's risk had changed since the ESM case, the AG responded that the

[139] Rosenberg Rebuttal Testimony at 4.

risk had changed very little.[140] To further demonstrate that the AG's recommendation is too low, LG&E compared the AG's recommendation to the 11.00 percent average electric ROE awarded nationally by utility regulatory commissions in 2003.[141]

In rebutting the AG's recommendation, LG&E stated that the AG's analysis employs misstated and misapplied approaches. LG&E identified calculations that it considers incorrectly performed and, when corrected, produce a higher result. LG&E also addressed the two "fatal errors" that the AG identified in LG&E's analysis. LG&E defended its use of inputs, reiterating that: (1) its use of the CPI as a measure of inflation was appropriate; and (2) the AG's contention that it had added rather than multiplied in the GDP calculation was, in fact, incorrect.[142]

The Commission finds merit in both LG&E's and the AG's recommended ranges for ROE and their critiques of each other's analyses. The Commission takes note of several sources of agreement between LG&E and the AG. As LG&E points out in its rebuttal testimony, the AG's recommended range in the consolidated ESM case overlaps substantially with LG&E's recommended range. The Commission also takes note of the AG's upward revision to his recommendation due to the agreement to discontinue the ESM mechanism. LG&E recommended the top of its range in order to recognize its efficient management and the uncertain business environment. While the Commission is prohibited from using an ROE award to either reward or punish a utility's

[140] Response of the Attorney General to Requests for Information from LG&E, dated April 6, 2004, Item 32.

[141] Rosenberg Rebuttal Testimony at 2.

[142] Id. at 15-16.

management,[143] the Commission again takes note that the AG supported, in part, the need to increase the ROE award in recognition of the uncertain business climate when he increased some of his results by 95 basis points to allow for likely increases in interest rates in the near future. Finally, the Commission notes that LG&E has compared the returns on equity recommended by the intervenors to recent returns on equity allowed by regulators in other jurisdictions. LG&E states that an April 5, 2004 edition of *Major Rate Case Decisions* of Regulatory Research Associates reports an average allowed return for electric utilities in other jurisdictions of 11 percent in the first quarter of 2004.[144] The Commission takes notice that this same publication subsequently reported in May 2004 that the allowed returns on equity for electric utilities in other jurisdictions ranged from 9.50 percent to 11.22 percent.[145] While we agree with LG&E when it says that ROE awards granted by other commissions should not dictate this Commission's decision, those decisions do, however, indicate that the recommendations from both parties are well within the general level of recent allowed returns. Therefore, after weighing all the evidence of record, the Commission finds that LG&E's required ROE falls within a range of 10.00 percent to 11.00 percent with a midpoint of 10.50 percent.

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[143] South Central Bell Telephone Company v. Utility Regulatory Commission, Ky., 637 S.W. 2d 649 (1982).

[144] Rosenberg Rebuttal Testimony at 2.

[145] Regulatory Research Associates, Inc., Regulatory Focus, May 26 and May 28, 2004.

Rate of Return Summary

Applying the rates of 3.57 percent for long-term debt, 1.54 percent for short-term debt, 2.59 percent for preferred stock, and 10.50 percent for common equity to the capital structure produces an overall cost of capital of 6.79 percent. The cost of capital produces a rate of return on LG&E's electric rate base of 6.69 percent.

REVENUE REQUIREMENTS

The Commission has determined that, based upon an electric capitalization of $1,484,965,466 and an overall cost of capital of 6.79 percent, the net operating income that could be justified by the record for LG&E's electric operations is $100,829,155. Based on the adjustments found reasonable herein, LG&E's pro forma electric net operating income for the test year would be $73,812,333 and LG&E would need additional annual operating income of $27,016,822. After the provision for uncollectible accounts, the PSC Assessment, and state and federal income taxes, LG&E would have a revenue deficiency of $45,608,365. The calculation of this overall revenue deficiency is as follows:

Net Operating Income Found Reasonable	$100,829,155
Pro Forma Net Operating Income	73,812,333
Net Operating Income Deficiency	27,016,822
Gross Up Revenue Factor[146]	.5923655
Overall Revenue Deficiency	$ 45,608,365

[146] Rives Direct Testimony, Rives Exhibit 1, Schedule 1.39. The gross up revenue factor recognizes the impact the overall revenue deficiency will have on the provision for uncollectible accounts, the PSC Assessment, Kentucky income taxes, and federal income taxes.

However, as discussed above, LG&E is a signatory to the Partial Settlement and Stipulation. Thus, LG&E has indicated its willingness to accept an increase in electric annual revenues of $43,400,000. In determining the overall reasonableness of this alternative proposed increase by LG&E, the Commission has devoted a significant portion of this Order to evaluating LG&E's and the AG's proposed adjustments to capital, rate base, operating revenues, and operating expenses in light of our normal rate-making treatment.

The Commission has found that LG&E's required ROE falls within a range of 10.00 percent to 11.00 percent. Applying the findings herein on the reasonable costs of debt and preferred stock, and the range of return on common equity, to LG&E's electric capitalization would result in the following range of revenue increases:

Revenue Increase -- 10.00 percent ROE	$39,591,950
Revenue Increase -- LG&E Alternative Proposal	$43,400,000
Revenue Increase – Justifiable by Record	$45,608,365
Revenue Increase -- 11.00 percent ROE	$51,875,465

Based on the findings and conclusions herein, the Commission finds that the earnings resulting from the adoption of LG&E's alternative proposal for its electric operations will fall within a range reasonable for both LG&E and its electric ratepayers. The $43,400,000 electric revenue increase that LG&E is willing to accept will result in fair, just, and reasonable electric rates for LG&E. Therefore, the Commission will accept LG&E's alternative proposal that its electric revenues be increased by $43,400,000.

FINDINGS ON PARTIAL SETTLEMENT AND STIPULATION

Based upon a review of all aspects of the unanimous provisions in the Partial Settlement and Stipulation, an examination of the record, and being otherwise sufficiently advised, the Commission finds that the unanimous provisions are in the public interest and should be approved. These provisions include, but are not limited to, the VDT surcredit, a new HEA program, the dismissal of two specified court appeals, and the phase-out of the Pay As You Go program. The Commission's approval of the unanimous provisions is based solely on their reasonableness in toto and does not constitute precedent on any issue except as specifically provided for therein. Although we are approving all of the unanimous provisions, we have some concerns that need to be addressed at this time regarding certain aspects of those provisions.

Electric Residential Rate Design

The parties have agreed to eliminate LG&E's seasonal residential electric rates. Historically, LG&E's residential rates have been set at higher levels during the peak summer months of June through September than during the rest of the year. Due to the impact of residential air conditioning use on LG&E's summer peak demand, this rate design was implemented to encourage conservation during the summer peak season. While the Commission does not object to eliminating this peak season differential, we are concerned that it might have an adverse impact by causing LG&E's peak demand to increase. Therefore, we find that LG&E should be required to monitor its summer demand, beginning July 1, 2004 and continuing through September 30, 2006 to ascertain the impact on its demand, if any, resulting from this rate design change. We also find that LG&E should, within 90 days of the end of this monitoring period, prepare a brief analysis and report summarizing the results of its monitoring.

LG&E should compare the actual growth in its residential summer demand to the growth it has forecast for its residential summer demand. While many factors can affect the difference between actual and forecast demand growth, LG&E should determine whether any unanticipated growth is the result of the change to a single year-round energy rate for residential customers. The Commission will convene an informal conference with LG&E within 90 days of the end of this monitoring period in order to facilitate an informal review of LG&E's analysis. The Commission will, at that time or earlier if conditions warrant, determine the need to evaluate the impact that this rate design change may have on LG&E's summer peak demand and investigate whether the seasonal residential rates should be re-implemented.

New HEA Program

The Commission's approval of the unanimous provisions in the Partial Settlement and Stipulation includes the approval of the parameters of a new HEA program for LG&E. The HEA program will be funded by a 10-cent per residential meter per month charge for a period of 3 years. An electric or gas only residential customer of LG&E will pay 10 cents per month while a combined electric and gas customer will pay 20 cents per month. The charge will be set forth as a separate line item on each residential customer's bill.

The Commission certainly recognizes that low income households frequently have difficulties paying their utility bills. Consequently, financial assistance programs that subsidize the utility bills of those households are much needed. However, when these types of programs are funded through mandatory charges on residential utility bills, the common perception is that these charges are forced charitable contributions and they generate sincere objections from many ratepayers. While it will never be possible to eliminate every objection, ratepayers will certainly have a higher degree of acceptance of the funding for these programs if they can be assured that the funds collected will be fully accounted for and spent in the most efficient manner.

It is for this reason that the Commission has always urged the utility that will be the beneficiary to be a financial contributor to the assistance program. When an affected utility is at least partially funding an assistance program, the utility has a greater incentive to monitor the program expenditures and is in a better position to assure its ratepayers that the funds are being spent in the most efficient manner. Consequently, the Commission is disappointed that LG&E has chosen not to be a financial contributor to the HEA program which it has agreed to implement. We urge LG&E to reconsider this decision, but we recognize that we have no authority to require LG&E to fund such a program.

In any event, there is a real need for LG&E to actively monitor the implementation, operation, and expenditures of the HEA program. The Commission expects LG&E to fulfill this role so it can provide its ratepayers with the assurances they demand and deserve regarding the efficient expenditure of the HEA funds.

The Partial Settlement and Stipulation did not address when the 10-cent per residential meter per month charge would begin. The Commission does not believe it would be reasonable for this charge to begin on the same effective date as the rates contained in the Partial Settlement and Stipulation, primarily because the programmatic details of the HEA program have not been submitted to the Commission for approval as agreed to by the parties. The Commission finds that the HEA program 10-cent per residential meter per month charge should not be collected from ratepayers until the Commission has approved the programmatic details. The Partial Settlement and

Stipulation envisions the HEA program to have a commencement date of October 1, 2004. The Commission believes it will need 60 days to review the programmatic details. Therefore, the Commission expects that the programmatic details for the new HEA program would be submitted for approval no later than August 1, 2004.

In addition, prior Commission Orders outlined several concerns about previous HEA programs in the Orders in Case No. 2001-00323.[147] The Commission continues to have those same concerns, and expects the proponents of this new HEA to address those concerns when the programmatic details are submitted to the Commission for its review and approval.

OTHER ISSUES

Electric Interruptible Service

On June 17, 2004, LG&E filed a letter, which the Commission will treat as a motion, regarding a potential problem related to proposed changes to its interruptible service tariff. Those changes, as set forth in the unanimous provisions of the Partial Settlement and Stipulation shorten the notice of interruption, increase the maximum number of hours of interruption, and increase the potential frequency of interruptions. LG&E believes that due to these changes some customers may, for operational reasons, want to switch from interruptible service to firm service. Consequently, LG&E is requesting authority to waive the 6-month notice required for a customer to terminate service under this tariff. This authority will permit LG&E to give the six customers

[147] Case No. 2001-00323, Joint Application of Louisville Gas and Electric Company, Metro Human Needs Alliance, People Organized and Working for Energy Reform, Kentucky Association for Community Action, and Jefferson County Government for the Establishment of a Home Energy Assistance Program, final Order dated December 27, 2001; rehearing Order dated January 29, 2002.

currently on this tariff the option to terminate service immediately, rather than being required to continue taking interruptible service for an additional 6 months.

Based on the significance of the changes in the terms and conditions of interruptible service, the Commission finds that LG&E's request to waive the 6-month notice of termination is reasonable. However, it is impractical for LG&E and an interruptible customer to switch rate schedules either immediately or on the effective date of the revised interruptible service tariff. Therefore, LG&E will be authorized to contact interruptible customers immediately upon issuance of this Order and inform them that they have a one-time opportunity to waive the 6-month notice of termination. Those customers will have until July 31, 2004 to notify LG&E if they elect to terminate interruptible service and switch to a firm service tariff.

Midwest Independent Transmission System Operator, Inc. ("MISO") Exit Fee

LG&E is currently a member of the Midwest Independent Transmission System Operator, Inc. ("MISO"), a regional transmission organization. In Case No. 2003-00266,[148] LG&E has requested authority to exit MISO and recover any exit fee from ratepayers. In this rate case, LG&E and the AG have addressed how the exit fee should be accounted for and what rate-making treatment is appropriate in the event the Commission authorizes LG&E to exit MISO. However, since the Commission has not yet decided whether LG&E should exit MISO, issues related to the accounting and rate-making treatment for an exit fee are premature. These issues will be addressed, if necessary, in Case No. 2003-00266.

[148] Case No. 2003-00266, Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.

The “Global Settlement”

On October 31, 2001, LG&E, KU, the AG, and KIUC filed a unanimous settlement agreement that was intended to operate as a full and complete resolution of five cases then pending before the Commission.[149] This settlement agreement, referred to as the “Global Settlement,” was approved by Commission Order on December 3, 2001. Several of the provisions of the Global Settlement directly affected adjustments proposed by LG&E in this rate case.

Article 1.0 of the Global Settlement provided that LG&E would perform a new depreciation study no later than calendar year 2004 based upon utility plant in service as of December 31, 2003 and when completed the new study would be filed with the Commission. LG&E did perform a new depreciation study which was filed in this case, but it was based on utility plant in service as of December 31, 2002. LG&E contended that this depreciation study was in compliance with the Global Settlement, arguing that, “the defining limit on the previous commitment was the timing of another study (e.g., ‘no later than calendar year 2004’),” and that it “did not believe the plant-in-service date was intended to be the defining limit ….”[150]

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[149] The five cases were Case No. 2001-00054, The Annual Earnings Sharing Mechanism Filing of Louisville Gas and Electric Company; Case No. 2001-00055, The Annual Earnings Sharing Mechanism Filing of Kentucky Utilities Company; Case No. 2001-00140, Application of Kentucky Utilities Company for an Order Approving Revised Depreciation Rates; Case No. 2001-00141, Application of Louisville Gas and Electric Company for an Order Approving Revised Depreciation Rates; and Case No. 2001-00169, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for an Order Approving Proposed Deferred Debits and Declaring the Amortization of the Deferred Debits to be Included in Earnings Sharing Mechanism Calculations.

[150] Response to the Commission Staff’s Third Data Request dated March 1, 2004, Item 21.

Article 2.0 of the Global Settlement addressed issues related to LG&E's VDT workforce reduction and authorized LG&E to establish a regulatory asset which would include the expenses incurred to achieve the savings associated with the VDT workforce reduction. At the time the Global Settlement was approved, the regulatory asset was to be established based on estimated expenses. Later, the regulatory asset was to be adjusted to reflect actual VDT-related expenses as of December 31, 2001. However, for rate-making purposes, the actual expenses could not exceed the preliminary estimated expenses. During this case, LG&E disclosed that it had increased the balance in the VDT regulatory asset by $680,800 for expenses incurred after December 31, 2001.[151] LG&E contended that recording these additional expenses as part of the regulatory asset was consistent with the recording of the estimated expenses permitted when the Commission approved the Global Settlement. LG&E argued that it was in compliance with the terms of the Global Settlement because these additional expenses did not cause the regulatory asset balance to exceed the settlement amount of the expenses. LG&E stated that while it did record the additional expenses as part of the regulatory asset, it did not make an adjustment to the net savings returned to ratepayers through the VDT surcredit.[152] LG&E did include adjustments in this rate case to revise the VDT amortization expense to correspond with the regulatory asset as it was recorded on December 31, 2001.

[151] LG&E recorded these additional expenses in the regulatory asset account between December 2002 and July 2003. See Response to the Commission Staff's Third Data Request dated March 1, 2004, Item 15(b)(1).

[152] Response to the Commission Staff's Fourth Data Request dated April 14, 2004, Item 3.

The Commission is concerned by LG&E's interpretation of provisions of the Global Settlement as reflected in this rate case. Contrary to LG&E's interpretation of the Global Settlement provision concerning the timing of its next depreciation study, it is clear that the calendar year 2004 deadline for filing and the utilization of utility plant in service as of December 31, 2003 are both controlling dates. Concerning the VDT regulatory asset, the Global Settlement did not contain any provisions that authorized LG&E to continue to increase the balance of the regulatory asset established on December 31, 2001. The fact that the additional expenses did not exceed the originally estimated expenses does not justify LG&E's accounting.

The Commission notes that, in Case No. 2002-00071, [153] LG&E previously misinterpreted provisions of the Global Settlement. In that case the Commission found that the Global Settlement did not authorize LG&E to adjust its monthly capitalization to retroactively reflect the VDT workforce reduction, and LG&E was required to recalculate its ESM annual filing for calendar year 2001.

The Commission will not require LG&E to submit a new depreciation study in compliance with the dates established in the Global Settlement since we are accepting LG&E's proposal to prepare a new depreciation study no later than June 30, 2007. In addition, we will not require LG&E to remove the post-2001 additions to its VDT regulatory asset since the amortization expenses that were included for rate-making purposes were consistent with the provisions of the Global Settlement and the

[153] Case No. 2001-00071, Louisville Gas and Electric Company's Annual Earnings Sharing Mechanism Filing for Calendar Year 2001.

regulatory asset is not included in rate base. Consequently, ratepayers have not been harmed by LG&E's actions.

The Commission is concerned, however, that on three separate occasions LG&E has incorrectly interpreted and deviated from significant provisions of the Global Settlement. The unanimous provisions of the Partial Settlement and Stipulation approved herein are significantly more encompassing and complex than the provisions contained in the Global Settlement. The Commission cautions LG&E that, absent prior Commission approval, there should be no deviations from either the unanimous provisions of that document or LG&E's timetable for filing a new depreciation study.

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by LG&E in its application are denied.

2. The ESM Settlement, attached hereto as Appendix B, is approved in its entirety and LG&E's ESM is terminated except for continued collections for 2003 operations.

3. The unanimous provisions in the Partial Settlement and Stipulation, attached hereto as Appendix C, are approved in their entirety.

4. The rates and charges in LG&E Electric Exhibit 1 and LG&E Gas Exhibit 1, set forth in Appendix A hereto, are the fair, just, and reasonable rates for LG&E to charge for electric and gas service, and these rates are approved for service rendered on and after July 1, 2004.

5. LG&E shall, within 20 days of the date of this Order, file its revised tariff sheets setting out the rates and tariff changes approved herein.

6. Within one year from the date of this Order, LG&E shall file with the Commission a plan developed and implemented that eliminates the underfunding of its pension and post-retirement plans. LG&E shall also file progress reports on its progress to eliminate the underfunding of the pension and post-retirement plans as described within this Order.

7. LG&E shall monitor its summer electric demand, beginning July 1, 2004 and continuing through September 30, 2006, to ascertain the extent of any impacts from the rate design changes approved herein. LG&E shall prepare an analysis and report as described in the findings above.

8. LG&E shall submit for Commission approval the programmatic details associated with its HEA program no later than August 1, 2004.

9. LG&E shall not bill its residential electric and gas customers 10 cents per meter per month for the HEA until authorized to do so upon Commission approval of the HEA programmatic details.

10. LG&E's request for a one-time waiver through July 31, 2004 of the 6-month customer notice to terminate interruptible electric service is granted.

Done at Frankfort, Kentucky, this 30th day of June, 2004.

By the Commission

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00433 DATED JUNE 30, 2004

The following rates and charges are prescribed for the customers in the area served by Louisville Gas & Electric Company, consistent with LG&E Electric Exhibit 1 and LG&E Gas Exhibit 1. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

ELECTRIC SERVICE RATES

SCHEDULE RS
RESIDENTIAL RATE

Customer Charge per Month:	$ 5.00
Energy Charge per kWh:	$ .05887

SCHEDULE RPM
PREPAID METERING PILOT PROGRAM

Facilities Charge per Month:	$ 2.05
Customer Charge per Month:	$ 5.00
Energy Charge per kWh:	$ .05887

SCHEDULE VFD
VOLUNTEER FIRE DEPARTMENT SERVICE

Customer Charge per Month:	$ 5.00
Energy Charge per kWh:	$ .05887

SCHEDULE GS
GENERAL SERVICE RATE

Customer Charge per Month – Single Phase:	$ 10.00
Customer Charge per Month – Three Phase:	$ 15.00
Energy Charge per kWh:	
Summer Season	$ .07086
Winter Season	$ .06313

SCHEDULE LC
LARGE COMMERCIAL RATE – PRIMARY VOLTAGE

Customer Charge per Month:	$ 65.00
Demand Charge per kW:	
Summer Season	$ 12.32
Winter Season	$ 9.52
Energy Charge per kWh:	$ .02349

SCHEDULE LC
LARGE COMMERCIAL RATE – SECONDARY VOLTAGE

Customer Charge per Month:	$ 65.00
Demand Charge per kW:	
Summer Season	$ 14.20
Winter Season	$ 11.14
Energy Charge per kWh:	$ .02349

SCHEDULE LC-TOD
LARGE COMMERCIAL TIME-OF-DAY PRIMARY VOLTAGE

Customer Charge per Month:	$ 90.00
Basic Demand Charge per kW:	$ 2.17
Peak Demand Charge per kW:	
Summer Season	$ 10.15
Winter Season	$ 7.35
Energy Charge per kWh:	$ .02349

SCHEDULE LC-TOD
LARGE COMMERCIAL TIME-OF-DAY SECONDARY VOLTAGE

Customer Charge per Month:	$ 90.00
Basic Demand Charge per kW:	$ 3.22
Peak Demand Charge per kW:	
Summer Season	$ 10.98
Winter Season	$ 7.92
Energy Charge per kWh:	$ .02349

SCHEDULE LP
INDUSTRIAL POWER RATE TRANSMISSION VOLTAGE

Customer Charge per Month:	$ 90.00
Demand Charge per kW:	
Summer Season	$ 11.35
Winter Season	$ 8.76
Energy Charge per kWh:	$ .02000

SCHEDULE LP
INDUSTRIAL POWER RATE PRIMARY VOLTAGE

Customer Charge per Month:	$ 90.00
Demand Charge per kW:	
Summer Season	$ 12.55
Winter Season	$ 9.96
Energy Charge per kWh:	$ .02000

SCHEDULE LP
INDUSTRIAL POWER RATE SECONDARY VOLTAGE

Customer Charge per Month:	$ 90.00
Demand Charge per kW:	
Summer Season	$ 14.35
Winter Season	$ 11.76
Energy Charge per kWh:	$ .02000

SCHEDULE LP-TOD
INDUSTRIAL POWER TIME-OF-DAY TRANSMISSION VOLTAGE

Customer Charge per Month:	$ 120.00
Demand Charge per kW:	$ 2.33
Peak Demand Charge per kW:	
Summer Season	$ 9.02
Winter Season	$ 6.43
Energy Charge per kWh:	$ .02000

SCHEDULE LP-TOD
INDUSTRIAL POWER TIME-OF-DAY PRIMARY VOLTAGE

Customer Charge per Month:	$ 120.00
Demand Charge per kW:	$ 3.52
Peak Demand Charge per kW:	
Summer Season	$ 9.03
Winter Season	$ 6.44
Energy Charge per kWh:	$ .02000

SCHEDULE LP-TOD
INDUSTRIAL POWER TIME-OF-DAY SECONDARY VOLTAGE

Customer Charge per Month:	$ 120.00
Demand Charge per kW:	$ 4.62
Peak Demand Charge per kW:	
Summer Season	$ 9.73
Winter Season	$ 7.14
Energy Charge per kWh:	$ .02000

SCHEDULE LI-TOD
LARGE INDUSTRIAL TIME-OF-DAY RATE TRANSMISSION VOLTAGE

Customer Charge per Month:	$120.00
Demand Charge per kVA:	$ 2.33
Peak Demand Charge per kVA:	
Summer Season	$ 9.02
Winter Season	$ 6.43
Energy Charge per kVA:	$ .02000

SCHEDULE LI-TOD
LARGE INDUSTRIAL TIME-OF-DAY RATE PRIMARY VOLTAGE

Customer Charge per Month:	$120.00
Demand Charge per kVA:	$ 3.52
Peak Demand Charge per kVA:	
Summer Season	$ 9.03
Winter Season	$ 6.44
Energy Charge per kWh:	$ .02000

SCHEDULE LI-TOD
LARGE INDUSTRIAL TIME-OF-DAY RATE SECONDARY VOLTAGE

Customer Charge per Month:	$120.00
Demand Charge per kVA:	$ 4.62
Peak Demand Charge per kVA:	
Summer Season	$ 9.73
Winter Season	$ 7.14
Energy Charge per kWh:	$ .02000

RATE CSR 1
CURTAILABLE SERVICE RIDER 1

	Transmission	Primary
Demand Credit per kW per Month	$ 3.10	$ 3.20
Non-compliance Charge Per kW Per Month	$ 16.00	$ 16.00

RATE CSR 2
CURTAILABLE SERVICE RIDER 2

	Transmission	Primary
Demand Credit per kW per Month	$ 3.98	$ 4.05
Non-compliance Charge Per kW Per Month	$ 16.00	$ 16.00

RATE CSR 3
CURTAILABLE SERVICE RIDER 3

	Transmission	Primary
Demand Credit per kW per Month	$ 3.10	$ 3.20
Non-compliance Charge Per kW Per Month	$ 16.00	$ 16.00

SCHEDULE SLE
STREET LIGHTING ENERGY RATE

Energy Charge per kWh:	$ .04059

SCHEDULE TLE
TRAFFIC LIGHTING ENERGY RATE

Customer Charge per Month:	$ 2.80
Energy Charge per kWh	$ .05114

SCHEDULE PSL
PUBLIC STREET LIGHTING SERVICE

	Rate per Month per Unit	
Overhead Service	To 1/1/1991	After 12/31/1990
Mercury Vapor		
100 Watt	$ 6.52	$ NA
175 Watt	$ 7.59	$ 9.45
250 Watt	$ 8.61	$ 10.57
400 Watt	$ 10.25	$ 12.65
400 Watt (Metal Pole)	$ 14.90	$ NA
1,000 Watt	$ 18.92	$ 22.78
High Pressure Sodium		
100 Watt	$ 7.80	$ 7.80
150 Watt	$ 9.32	$ 9.32
250 Watt	$ 11.12	$ 11.12
400 Watt	$ 11.49	$ 11.49
1,000 Watt	$ NA	$ 26.13
Underground Service		
Mercury Vapor		
100 Watt-Top Mounted	$ 10.68	$ 13.19
175 Watt-Top Mounted	$ 11.65	$ 14.28
175 Watt	$ 15.84	$ 22.56
250 Watt	$ 16.90	$ 23.68
400 Watt	$ 19.83	$ 25.76
400 Watt (State of Ky. pole)	$ 19.83	$ 25.76
High Pressure Sodium Vapor		
70 Watt-Top Mounted	$ NA	$ 11.31
100 Watt-Top Mounted	$ 11.73	$ 11.73
150 Watt-Top Mounted	NA	$ 17.35
150 Watt	$ 20.33	$ 20.33
250 Watt	$ 21.51	$ 21.51
250 Watt on State of Ky. Pole	$ 21.51	$ 21.51
400 Watt	$ 22.97	$ 22.97
400 Watt on State of Ky. Pole	$ 22.97	$ 22.97
1000 Watt	$ NA	$ 53.45
Decorative Lighting Service		Rate per month

Fixtures	
Acorn with Decorative Basket	
70 Watt High Pressure Sodium	$ 15.62
100 Watt High Pressure Sodium	$ 16.25
8-Sided Coach	
70 Watt High Pressure Sodium	$ 15.83
100 Watt High Pressure Sodium	$ 16.44
Poles	
10 ft. Smooth	$ 9.36
10 ft. Fluted	$ 11.17
Bases	
Old Town/Manchester	$ 3.00
Chesapeake/Franklin	$ 3.22
Jefferson/Winchester	$ 3.25
Norfolk/Essex	$ 3.42

SCHEDULE OL
OUTDOOR LIGHTING SERVICE

	Rate per Month per Unit	
Overhead Service	To 1/1/1991	After12/31/1990
Mercury Vapor		
100 Watt	$ 7.27	$ NA
175 Watt	$ 8.18	$ 9.64
250 Watt	$ 9.25	$ 10.77
400 Watt	$ 11.19	$ 12.85
1000 Watt	$ 20.30	$ 23.05
High Pressure Sodium		
100 Watt	$ 8.07	$ 8.07
150 Watt	$ 10.32	$ 10.32
250 Watt	$ 12.14	$ 12.14
400 Watt	$ 12.75	$ 12.75
1000 Watt	$ NA	$ 30.20
Additional Pole Charge	$ 1.78	$ 1.78
Underground Service		
Mercury Vapor		
100 Watt Top Mounted	$ 12.70	$ 13.48
175 Watt Top Mounted	$ 13.48	$ 14.49
High Pressure Sodium		
70 Watt Top Mounted	$ 11.31	$ 11.31
100 Watt Top Mounted	$ 14.94	$ 14.94
150 Watt Top Mounted	$ NA	$ 18.11
150 Watt	$ 20.35	$ 20.35

250 Watt	$ 23.29	$ 23.29
400 Watt	$ 25.57	$ 25.57
1000 Watt	$ NA	$ 57.51

Decorative Lighting Service	Rate per month
Fixtures	
Acorn with Decorative Basket	
70 Watt High Pressure Sodium	$ 16.03
100 Watt High Pressure Sodium	$ 16.77
8-Sided Coach	
70 Watt High Pressure Sodium	$ 16.21
100 Watt High Pressure Sodium	$ 16.95
Poles	
10 ft. Smooth	$ 9.36
10 ft. Fluted	$ 11.17
Bases	
Old Town/Manchester	$ 3.00
Chesapeake/Franklin	$ 3.22
Jefferson/Winchester	$ 3.25
Norfolk/Essex	$ 3.42

SCHEDULE LS
LIGHTING SERVICE

Underground Service

	Lumen Output (approximate)	Monthly Rate Per Light
High Pressure Sodium		
4 Sided Colonial	6,300	$ 15.54
4 Sided Colonial	9,500	$ 16.05
4 Sided Colonial	16,000	$ 17.01
Acorn	6,300	$ 15.88
Acorn	9,500	$ 17.85
Acorn (Bronze Pole)	9,500	$ 18.74
Acorn	16,000	$ 18.80
Acorn (Bronze Pole)	16,000	$ 19.62
Contemporary	16,000	$ 24.18
Contemporary	28,500	$ 26.61
Contemporary	50,000	$ 29.95
Cobra Head	16,000	$ 21.10
Cobra Head	28,500	$ 22.80
Cobra Head	50,000	$ 26.18

* London (10' Smooth Pole)	6,300	$ 27.18
* London (10' Fluted Pole)	6,300	$ 28.89
* London (10' Smooth Pole)	9,500	$ 27.84
* London (10' Fluted Pole)	9,500	$ 29.56
* Victorian (10' Smooth Pole)	6,300	$ 26.34
* Victorian (10' Fluted Pole)	6,300	$ 28.06
* Victorian (10' Smooth Pole)	9,500	$ 26.91
* Victorian (10' Fluted Pole)	9,500	$ 28.62
* Bases Available:		
Old Town / Manchester		$ 2.53
Chesapeake / Franklin		$ 2.53
Jefferson / Westchester		$ 2.53
Norfolk / Essex		$ 2.69
Mercury Vapor		
4 Sided Colonial	4,000	$ 15.60
4 Sided Colonial	8,000	$ 17.05
Cobra Head	8,000	$ 21.09
Cobra Head	13,000	$ 22.43
Cobra Head	25,000	$ 25.26
Overhead Service		
High Pressure Sodium		
Cobra Head	16,000	$ 9.16
Cobra Head	28,500	$ 10.86
Cobra Head	50,000	$ 14.24
Directional Flood	16,000	$ 10.60
Directional Flood	50,000	$ 15.11
Open Bottom	9,500	$ 8.01
Mercury Vapor		
Cobra Head	8,000	$ 9.15
Cobra Head	13,000	$ 10.49
Cobra Head	25,000	$ 13.32
Directional Flood	25,000	$ 14.69
Open Bottom	8,000	$ 8.89
Additional Pole Charge		$ 9.79

STANDARD RIDER FOR SUPPLEMENTAL OR STANDBY SERVICE

The monthly bill shall in no case be less than an amount calculated at the rate of $6.25 per kW applied to the contract demand.

STANDARD RIDER FOR REDUNDANT CAPACITY CHARGE

Capacity Reservation Charge Per kW Per Month:

Secondary Distribution	$ 1.43
Primary Distribution	$ 1.06

EXPERIMENTAL LOAD REDUCTION INCENTIVE RIDER

Rate:	Up to $ 0.30 per kWh

RATE STOD EXPERIMENTAL SMALL TIME-OF-DAY SERVICE

Customer Charge per Month:		$ 80.00
Energy Charge per kWh:		
On Peak		$ .02936
Off Peak		$ .01370
Demand Charge per kW:	Secondary	Primary
Summer Season	$ 14.20	$ 12.32
Winter Season	$ 11.14	$ 9.52

STANDARD RIDER FOR EXCESS FACILITIES

Charge for Distribution Facilities

Carrying Cost:	0.94%
Operating Expenses:	0.68%

RETURNED CHECK CHARGE

Rate:	$ 7.50

METER TEST CHARGE

Rate:	$ 31.40

DISCONNECT AND RECONNECT SERVICE CHARGE

Rate:	$ 20.00

SPECIAL CONTRACT
FORT KNOX

Demand Charge Per kW Per Month:	
Summer Season	$ 11.94
Winter Season	$ 9.75
Energy Charge Per kWh:	$ 0.02000

SPECIAL CONTRACT
DUPONT

Demand Charge Per kW Per Month:	$ 11.15
Energy Charge Per kWh:	$ 0.02000

SPECIAL CONTRACT
UNITED PARCEL SERVICE

Customer Charge Per Month:	$ 120.00
Demand Charge Per kW Per Month:	
Basic Demand Charge	$ 6.30
Seasonal Demand Charge	
Summer Season	$ 7.65
Winter Season	$ 3.27
Energy Charge Per kWh:	$ 0.02000

SPECIAL CONTRACT
GENERAL ELECTRIC

Customer Charge Per Month:	$ 74.29
Demand Charge Per kW Per Month:	
Basic Demand Charge	$ 4.62
Seasonal Demand Charge	
Summer Season	$ 7.65
Winter Season	$ 3.27
Energy Charge Per kWh:	$ .02000

SPECIAL CONTRACT
LOUISVILLE WATER COMPANY

Demand Charge Per kW Per Month:	$ 8.33
Energy Charge Per kWh:	$ .01988

GAS SERVICE RATES

RATE RGS
RESIDENTIAL GAS SERVICE

Customer Charge Per Month:	$ 8.50
Distribution Charge Per Ccf:	$ .15470

RATE VFD
VOLUNTEER FIRE DEPARTMENT SERVICE

Customer Charge Per Month:	$ 8.50
Distribution Charge Per Ccf:	$ .15470

RATE CGS
FIRM COMMERCIAL GAS SERVICE

Customer Charge Per Month:	
Meters < 5000 cf/hr	$ 16.50
Meters >= 5000 cf/hr	$ 117.00
Distribution Charge	
On Peak Ccf:	$ .14968
Off Peak Ccf:	$ .09968

Transportation Service/Standby Rider to Rate CGS

Administrative Charge Per Month:	$ 90.00
Distribution Charge	
On Peak Ccf:	$ .14968
Off Peak Ccf:	$ .09968

RATE IGS
FIRM INDUSTRIAL GAS SERVICE

Customer Charge Per Month:	
Meters < 5000 cf/hr	$ 16.50
Meters >= 5000 cf/hr	$ 117.00
Distribution Charge	
On Peak Ccf:	$ .14968
Off Peak Ccf:	$ .09968

Transportation Service/Standby Rider to Rate IGS

Administrative Charge Per Month:	$ 90.00
Distribution Charge	
On Peak Ccf:	$ .14968
Off Peak Ccf:	$ .09968

RATE AAGS
AS AVAILABLE GAS SERVICE

Current Rate G-6 and G-6/TS Customers

Customer Charge Per Month	$ 150.00
Distribution Charge Per Ccf:	$ .05252

Current Rate G-6 Customers

Customer Charge Per Month:	$ 150.00
Distribution Charge Per Ccf:	$ .05252

RATE FT
FIRM TRANSPORTATION SERVICE
(NON-STANDBY)

Administrative Charge Per Month:	$ 90.00
Distribution Charge Per Ccf:	$ .4300
Utilization Charge for Daily Imbalances Per Ccf	$ .3807

RATE PS-FT
POOLING SERVICE RIDER TO RATE FT

PS-FT Pool Administration Charge: $75 per customer in FT Pool per month.

RATE RBS
RESERVE BALANCING SERVICE

Applicable to Reserved Balance Volume

Monthly Demand Charge Per Mcf:	$ 5.1700
Monthly Balancing Charge Per Mcf:	$ 3.6500
Total	$ 8.8200

STANDARD RIDER FOR EXCESS FACILITIES

Charge for Distribution Facilities

Carrying Cost:	0.94%
Operating Expenses:	0.68%

RETURNED CHECK CHARGE

Rate: $ 7.50

METER TEST CHARGE

Rate: $ 69.00

DISCONNECT AND RECONNECT SERVICE CHARGE

Rate: $ 20.00

INSPECTION CHARGE

Rate: $ 135.00

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00433 DATED JUNE 30, 2004

ESM SETTLEMENT AGREEMENT
Dated May 12, 2004

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 12th day of May 2004, by and between Louisville Gas and Electric Company ("LG&E"); Kentucky Utilities Company ("KU") (LG&E and KU are hereafter collectively referenced as "the Utilities"); Commonwealth of Kentucky, ex. rel. Gregory Stumbo, Attorney General, by and through the Office of Rate Intervention ("AG"); Kentucky Industrial Utility Customers, Inc. ("KIUC") and the interests of its participating members as represented by and **through** the KIUC; Commonwealth of Kentucky, Environmental and Public Protection Cabinet, Division of Energy ("KDOE"); the United States Department of Defense ("DOD); The Kroger Company ("Kroger"); Kentucky Association for Community Action, Inc. ("KACA"); Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"); Metro Human Needs Alliance ("MHNA"); People Organized and Working for Energy Reform ("POWER'); Lexington-Fayette Urban County Government ("LFUCG); and North American Stainless, L.P. ("NAS") in the proceedings involving LG&E and KU which are the subject of this Settlement Agreement, ***as*** set forth below.

W I T N E S S E T R :

WHEREAS, LG&E filed on December 29, 2003 with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Rates, ***In*** *Re the Matter of: **An** Adjustment of the Gas and Electric Rates. Terms and Conditions of Louisville* Gar *and Electric Comuanv,* and the Commission has established Case No. 2003-00433 to review LG&E's base rate application;

WHEREAS, KU filed on December 29, 2003 with the Commission its Application for Authority to Adjust Rates, *In Re the Matter of: An Adjustment **of** the Electric Rates, Terms and Conditions of Kentucky Utilities Comuanv*, and the Commission has established Case No. 2003-00434 to review KU's base rate application;

WHEREAS, the AG, KIUC, KDOE and Kroger have been granted intervention by the Commission in both of the forgoing proceedings; MHNA, POWER, DOD and KACA have been granted intervention by the Commission in Case No. 2003-00433 only; and LFUCG, NAS and CAC have been granted intervention by the Commission in Case No. 2003-00434 only;

WHEREAS, on March 31, 2004, the Commission granted consolidation of Case No. 2003-00433 with the case captioned *In Re the Matter of An Investigation Pursuant to KRS 278.260 of the Earnings Sharing Mechanism Tariff of Louisville Gas and Electric Company*, Case No. 2003-00335;

WHEREAS, on March 31, 2004, the Commission granted consolidation of Case No. 2003-00434 with the case entitled *In Re the Matter of: An Investigation Pursuant to KRS 278.260 of the Earnings Sharing Mechanism Tariff of Kentucky Utilities Company*, Case No. 2003-00334;

WHEREAS, the AG and KIUC have been granted intervention by the Commission in both Case Nos. 2003-00334 and 2003-00335; and LFUCG has been granted intervention by the Commission in Case No. 2003-00334 only;

WHEREAS, LG&E's current Earnings Sharing Mechanism tariff was effective on January 2, 2003 pursuant to the Commission's Orders of December 20, 2002 and January 14, 2003 in Case No 2002-00473 (LG&E); and KU's current ESM tariff was effective on January 2, 2003 pursuant to the Commission's Orders of December 20,2002 and January 14,2003 in Case No. 2002-00472 (collectively the "ESM tariffs");

WHEREAS, on March 1, 2004 LG&E filed its Annual Earnings Sharing Mechanism Filing for Calendar Year 2003 in Case No. 2004-00069;

WHEREAS, on March 1,2004 KU filed its Annual Earnings Sharing Mechanism Filing for Calendar Year 2003 in Case No. 2004-00070;

WHEREAS, a prehearing conference, attended in person or by teleconference by representatives of the AG, KIUC, KDOE, DOD, Kroger, KACA, CAC, MHNA, POWER, LFUCG, NAS, the Commission Staff and the Utilities, took place on April 28, 2004 at the offices of the Commission during which a number of procedural and substantive issues were discussed, including potential settlement of certain issues pending before the Commission in Case Nos. 2003-00433 and 2003-00434, Case Nos. 2003-00334 and 2003-00335 (the "ESM renewal proceedings"), and Case Nos. 2004-00069 and 2004-00070 (the "2003 ESM proceedings"); and

WHEREAS, the signatories hereto desire to settle certain issues pending before the Commission in the rate proceedings, the ESM renewal proceedings and the 2003 ESM proceedings.

NOW, THEREFORE, for and in consideration of the premises and conditions set forth herein, the parties hereby agree as follows:

ARTICLE I. **Earnings Sharing Mechanism ("ESM") Recoverv and Discontinuation**

SECTION 1.1 Effective July 1,2004, the Earnings Sharing Mechanism, except as set forth in Sections 1.2 through 1.4 below, shall be discontinued,

SECTION 1.2 LG&E has filed with the Commission, in Case No. 2004-0069, the results for the 2003 ESM Reporting Period and the corresponding ESM billing factor pursuant to its ESM tariff. Beginning April 1, 2004, LG&E began billing its 2003 ESM factor in customer bills. The parties recommend the Commission issue an order in Case No.

2004-0069 approving the 2003 ESM factor as filed and authorizing LG&E to continue billing its ESM factor through March 31, 2005 and collect and retain all the revenues derived from the billing of 2003 ESM factor. Specifically, for the period of April 1, 2004 through April 30, 2004, LG&E should be allowed to bill, collect and retain amounts permitted under its ESM tariff with an ESM factor of 2.282%. And, specifically, for the period of May 1, 2004 through March 31, 2005, LG&E should be allowed to bill, collect and retain amounts permitted under its ESM tariff with an ESM factor of 2.360%.

SECTION 1.3 KU has filed with the Commission, in Case No. 2004-0070, the results for the 2003 ESM Reporting Period and the corresponding ESM billing factor pursuant to its ESM tariff. Beginning April 1, 2004, KU began billing its 2003 ESM factor in customer bills. The parties recommend the Commission issue an order in Case No. 2004-0070 approving the 2003 ESM factor as filed and authorizing KU to continue billing its ESM factor through March 31, 2005 and collect and retain all the revenues derived from the billing of 2003 ESM factor. Specifically, for the period of April 1, 2004 through April 30, 2004, KU should be allowed to bill, collect and retain amounts permitted under its ESM tariff with an ESM factor of 2.367%. And, specifically, for the period of May 1, 2004 through March 31, 2005, KU should be allowed to bill, collect and retain amounts permitted under its ESM tariff with an ESM factor of 2.330%.

SECTION I.4 No later than May 2005, the Utilities shall perform a final balancing adjustment to reconcile any over- or under-collection of the ESM revenues for the current ESM billing period, April 2004 through March 2005.

SECTION 1.5 The Utilities agree to waive their rights to make any billing or seek any collection under their respective ESM tariffs for the six-month period ending June 30, 2004, excluding the operation of the ESM mechanism as provided in Sections 1.2 through 1.4 above.

ARTICLE II. Approval of Settlement Agreement

SECTION 2.1 Following the execution of this Settlement Agreement, the signatories shall cause the Settlement Agreement to be filed with the Commission with a request to the Commission for consideration and approval of this Settlement Agreement by May ____, 2004.

SECTION 2.2 The signatories to this Settlement Agreement shall act in good faith and use their best efforts to recommend to the Commission that this Settlement Agreement be accepted and approved.

SECTION 2.3 If the Commission issues a final order which accepts and approves this Settlement Agreement in its entirety, then the parties hereto hereby waive any and all claims or demands, asserted or unasserted, directly arising out of or in connection with the application or operation of the Utilities' respective ESMs in Case Nos. 2004-0069, 2004-070, 2003-00334 and 2003-00335, and all such claims or demands shall be deemed settled under or compromised, released and discharged by this Settlement Agreement.

SECTION 2.4 If the Commission does not accept and approve this Settlement Agreement in its entirety, then: (a) this Settlement Agreement shall be void and withdrawn by the parties hereto from further consideration by the Commission and none of the parties shall be bound by any of the provisions herein; and (b) neither the teims of this Settlement Agreement nor any matters raised during the settlement negotiations shall be binding on any of the signatories to this Settlement Agreement or be construed against any of the signatories.

SECTION 2.5 Should the Settlement Agreement be voided or vacated for any reason after the Commission has approved the Settlement. Agreement and thereafter any implementation of the terms of the Settlement Agreement has been made, then the parties shall be returned to the *status quo* existing at the time immediately prior to the execution of this agreement.

ARTICLE III. <u>Additional Provisions</u>

SECTION 3.1 This Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

SECTION 3.2 This Settlement Agreement shall inure to the benefit of and be binding upon the parties hereto, their heirs, successors and assigns.

SECTION 3.3 This Settlement Agreement constitutes the complete agreement and understanding among the parties hereto, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

SECTION 3.4 For the purpose of this Settlement Agreement only, the terms are based upon the independent analysis of the parties to reflect a just and reasonable resolution of the issues herein and are the product of compromise and negotiation. Notwithstanding anything contained in the Settlement Agreement, the parties recognize and agree that the effects, if any, of any future events upon the operating income of LG&E or KU are unknown and this Settlement Agreement shall be implemented as written.

SECTION 3.5 Neither the Settlement Agreement nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Settlement Agreement. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

SECTION 3.6 The provisions of this Settlement Agreement shall not bar a party from seeking, or the Commission from reinstating, an ESM at some future time, in order to accomplish reasonable and valid regulatory objectives.

SECTION 3.7 Making this Settlement Agreement shall not be deemed in any respect to constitute an admission by any party hereto that any computation, formula, allegation, assertion or contention made by any other **party** in these proceedings is true or valid.

SECTION 3.8 The signatories hereto warrant that they have informed, advised, and consulted with the respective parties hereto in regard to the contents and significance of this agreement and based upon the foregoing are authorized to execute this Settlement Agreement on behalf of the parties hereto.

SECTION 3.9 This Settlement Agreement is subject to the acceptance of and approval by the Public Service Commission.

SECTION 3.10 This Settlement Agreement is a product of negotiation among all parties hereto, and no provision of this Settlement Agreement shall be strictly construed in favor of or against any party.

SECTION 3.11 This Settlement Agreement may be executed in multiple counterparts.

IN WITNESS WHEREOF, the parties hereto have hereunto affixed their signatures.

Louisville Gas and Electric Company
and Kentucky Utilities Company

HAVE READ AND AGREED:

By: Kendrick R. Riggs
Kendrick R. Riggs, Counsel

-and-

By: ______________________
Dorothy E. O'Brien, Counsel

Commonwealth of Kentucky, **ex.** rel. Gregory Stumbo, Attorney General, by and through the Office of Rate Intervention

HAVE READ AND AGREED:

By: ______________________
Elizabeth E. Blackford, Counsel

Kentucky Industrial Utility Customers, Inc.

HAVE READ AND AGREED:

By: ______________________________
David F. Boehm, Counsel
Michael L. Kurtz, Counsel

Commonwealth of Kentucky,
Environmental **and** Public Protection Cabinet,
Division of Energy

HAVE READ AND AGREED:

By: ______________________
Iris Skidmore, Counsel

United States Department of Defense

HAVE SEEN AND AGREED:

By: Peter A. Nyce, Jr.

for: David A. McCormick, Counsel

The Kroger Company

HAVE READ AND AGREED:

By: ______________________________

David C. Brown, Counsel

Kentucky Association for Community
Action, Inc.

HAVE READ **AND** AGREED:

By: ______________________________
Joe F. Childers, Counsel

Community Action Council for
Lexington-Fayette, Bourbon, Harrison
and Nicholas Counties, Inc.

HAVE READ AND AGREED:

By: ______________________
Joe F. Childers, Counsel

Metro Human Needs Alliance

HAVE READ AND AGREED:

By: ______________________________
Lisa Kilkelly, Counsel

People Organized and Working for Energy Reform

HAVE READ AND AGREED:

Ey: Lisa Kilkelly

Lisa Kilkelly, Counsel

Lexington-Fayette Urban County Government

HAVE READ AND AGREED:

By: ______________________

David J. Barberie, Counsel

North American Stainless, L.P.

HAVE READ AND AGREED:

By: ______________________
Richard S. Taylor, Counsel

By: ______________________
Nathaniel K. Adams, General Counsel

By: ______________________
Kimberly McCann, Counsel

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00433 DATED JUNE 30, 2004

PARTIAL SETTLEMENT AND STIPULATION

Dated May 12, 2004

<u>**PARTIAL SETTLEMENT AGREEMENT, STIPULATION AND RECOMMENDATION**</u>

This Partial Settlement Agreement, Stipulation and Recommendation ("Settlement Agreement") is entered into this 12th day of May 2004, by and between Louisville Gas and Electric Company ("LG&E"); Kentucky Utilities Company ("KU") (LG&E and KU are hereafter collectively referenced as "the Utilities"); Commonwealth of Kentucky, ex. rel. Gregory Stumbo, Attorney General, by and through the Office of Rate Intervention ("AG); Kentucky Industrial Utility Customers, Inc. ("KIUC") and the interests of its participating members as represented by and through the KIUC; Commonwealth of Kentucky, Environmental and Public Protection Cabinet, Division of Energy ("KDOE"); the United States Department of Defense ("DOD"); The Kroger Co.("Kroger"); Kentucky Association for Community Action, Inc. ("KACA"); Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"); Metro Human Needs Alliance ("MHNA"); People Organized and Working for Energy Reform ("POWER); Lexington-Fayette Urban County Government ("LFUCG"); and North American Stainless, L.P. ("NAS") in the proceedings involving LG&E and KU which are the subject of this Settlement Agreement, as set forth below.

W I T N E S S E T H:

WHEREAS, LG&E **filed** on December 29, 2003 with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Rates, ***<u>In Re the Matter of An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company</u>***, and the Commission has established Case No. 2003-00433 to review LG&E's base rate application;

WHEREAS, KU filed on December **29,** 2003 with the Commission its Application for Authority to Adjust Rates, ***<u>In Re the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company</u>***, and the Commission has established Case No. 2003-

00434 to review KU's base rate application (Case Nos. 2003-00433 and 2003-00434 are hereafter collectively referenced as the "rate proceedings");

WHEREAS, the AG, KIUC, KDOE, KACA and Kroger have been granted intervention by the Commission in both of the rate proceedings; MHNA, POWER and DOD have been granted intervention by the Commission in Case No. 2003-00433 only; and LFUCG, NAS and CAC have been granted intervention by the Commission in Case No. 2003-00434 only;

WHEREAS, on March 31, 2004, the Commission granted consolidation of Case Nos. 2003-00433 and 2003-00434 with the case captioned *In the Matter of: Tariff Filing of Kentucky Utilities Company and Louisville Gas and Electric Company for Non-Conforming Load Customers*, Case No. 2003-00396 (which case had previously been consolidated with *In the Matter oft North American Stainless v. Kentucky Utilities Company*, Case No. 2003-00376).

WHEREAS, a prehearing conference, attended in person or by teleconference by representatives of the AG, KIUC, KDOE, DOD, Kroger, KACA, CAC, MHNA, POWER, LFUCG, NAS, the Commission Staff and the Utilities, took place on April 28, 2004 at the offices of the Commission during which a number of procedural and substantive issues were discussed, including potential settlement of certain issues pending before the Commission in the rate proceedings;

WHEREAS, on May 4, 2004, the hearing in the rate proceedings began and was adjourned for the purpose of exploring the possibility of settlement of the rate proceedings or stipulation of issues therein, which discussions were attended in person by representatives of the AG, KIUC, KDOE, DOD, Kroger, KACA, CAC, MHNA, POWER, LFIJCG, NAS, the Commission Staff and the Utilities;

WHEREAS, all of the signatories hereto desire to settle all the issues pending before the Commission in the rate proceedings, except for the AG, who is unwilling to settle the issue of the revenue requirements of LG&E's electric operations and KU's operations;

WHEREAS, it is understood by all signatories hereto that this Settlement Agreement is subject to the approval of the Commission, insofar as it constitutes an agreement by all parties to the rate proceedings for settlement, and does not represent agreement on any specific theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms and conditions;

WHEREAS, it is understood by all signatories hereto that, insofar as this Settlement Agreement does not recite the agreement of the **AG** to settle the issue of the revenue requirements of the LG&E electric operations and the KU operations, it is a stipulation among the signatories hereto other than the AG as to the foregoing revenue requirement issues, pursuant to 807 KAR 5:001, Section 4(6);

WHEREAS, the signatories have spent many hours, over several days, in order to reach the stipulations and agreements which form the basis of this Settlement Agreement;

WHEREAS, all of the signatories, who represent diverse interests and divergent viewpoints, agree that this Settlement Agreement, viewed in its entirety, is a fair, just and reasonable resolution of all the issues in the rate proceedings;

WHEREAS, the adoption of this Settlement Agreement will reduce the length of the hearing, simplify the briefing, and eliminate the possibility of, and any need for, rehearing on the issues stipulated and agreed to; and

WHEREAS, it is the position of the parties hereto that this Settlement Agreement is supported by sufficient and adequate data and information, and should be approved by the Commission.

NOW, THEREFORE, for and in consideration of the premises and conditions set forth herein, the parties hereby stipulate and agree as follows:

ARTICLE I. Revenue Requirement.

Section 1.1. The signatories hereto, except the AG, stipulate that the following annual increases in revenues for LG&E electric operations and for KU operations, for purposes of determining the rates of LG&E and KU in the rate proceedings, are fair, just and reasonable for the signatories and for all customers of LG&E (electric) and KU:

Section 1.1.1. LG&E Electric Operations: $43,400,000;

Section 1.1.2. KU Operations: $46,100,000.

The signatories hereto, including the AG, agree that any annual increase in revenues for LG&E electric operations and for KU operations will be effective July 1, 2004.

Section 1.2. The signatories hereto, including the AG, agree that, effective July 1, 2004, the annual increases in revenues for LG&E gas operations of $11,900,000, for purposes of determining the rates of LG&E gas operations in the rate proceedings, are fair, just and reasonable for the signatories and for all gas customers of LG&E.

ARTICLE II. Allocation of Revenue.

Section 2.1. The signatories hereto, including the AG, agree that the allocation of the annual revenue increase for LG&E electric operations, LG&E gas operations and for KU operations, as set forth on the allocation schedule designated Exhibit 1 hereto, in the rate proceedings is fair, just and reasonable for the signatories and for all customers of LG&E and KU. Notwithstanding the foregoing sentence, it is understood that the AG has only agreed that the percentages of the rate classes applicable to each LG&E electric operations rate class and each KU operations rate class on Exhibit 1 hereto are fair, just and reasonable and the AG has made no agreement of any other information relating to such LG&E electric operations or KU operations. All signatories hereto, including the AG, agree that the revenue increase to electric special contract customers set forth on Exhibi! **1** hereto shall be allocated such that each special contract customer shall have the same percentage increase in rates.

Section 2.2. The signatories hereto, except the AG, agree that, effective July 1. 2004, the Utilities shall implement the electric rates set forth on Exhibit 1, attached hereto, which rates the signatories hereto, except the AG, stipulate are fair, just and reasonable and should be approved by the Commission. All signatories hereto, including the AG, agree that. effective July 1, **2004,** the Utilities shall implement the **gas** rates set forth on Exhibit 1, attached hereto, which rates the signatories hereto agree are fair, just and reasonable and should be approved by the Commission.

Section 2.3. The signatories hereto, including the AG, agree that the Utilities shall establish **a** pilot time-of-day program for commercial customers with a monthly demand between 250 kW and 2,000 kW. The rates, terms and conditions of said program shall be as set forth in the Stipulation, dated May **4,** 2004, between the Utilities and Kroger and filed in the rate proceedings. A copy of said Stipulation is attached hereto as Exhibit 2 and is incorporated by reference as though fully set forth herein. The forms of tariff designed to implement the Stipulation and the Settlement Agreement are attached hereto as Exhibit 2-A (LG&E) and Exhibit 2-B (KU).

ARTICLE III. Treatment of Certain Specific Issues.

Section 3.1. The signatories hereto, including the AG, agree that, after the date hereof, orders approving cost recovery of LG&E's and KU's environmental projects pursuant to KRS 278.183 shall be based upon an 11.0% return on common equity until directed by order of the Commission that a different rate of return shall be utilized.

Section 3.2. The signatories hereto, including the AG, agree that all of LG&E's gas purification and gas storage loss expenses shall be recovered as part of its Gas Supply Clause mechanism.

Section 3.3. The signatories hereto, except the AG, agree that the depreciation rates of the Utilities shall remain the same as approved in the orders of December 3, 2001, in Case Nos. 2001-140 and 2001-141, until the approval by the Commission of new depreciation rates for the Utilities, for which the

Utilities shall seek approval by filings made in their next general rate cases or June 30, 2007, whichever occurs earlier. The Utilities' depreciation filings shall be based on plant in service as of a date no earlier than one (1) year prior to such filing. From and after the effective date hereof, the Utilities shall maintain their books and records so that net salvage amounts may be identified.

Section 3.4. The signatories hereto, including the AG, agree that all costs associated with KU's 1994 environmental compliance plan (the "1994 Plan") approved in Case No. 93-465 and LG&E's 1995 environmental compliance plan (the "1995 Plan") approved in Case No. 94-332 shall be recovered in the Utilities' base rates, taking into account the Utilities' overall rate of return, and will be removed from the Utilities' monthly environmental surcharge filings, all in accordance with the details of such recovery set forth on Exhibit 3 hereto.

Section 3.5. The signatories hereto, including the AG, agree that, unless the Commission has already modified or terminated the Value Delivery Team ("VDT") surcredits in a subsequent rate case, six (6) months prior to the expiration of the sixty (60) month period in which the VDT surcredits are in operation, the Utilities shall file with the Commission a plan for the future ratemaking treatment of the VDT surcredits, the shareholder savings, the amortization of VDT costs and all other VDT-related issues. The VDT surcredit tariffs shall remain in effect following the expiration of the sixtieth (60^{th}) month until the Commission enters an order on the future ratemaking treatment of all VDT-related issues.

Section *3.6.* The signatories hereto, including the **AG,** agree that LG&E shall establish a real time pricing ("RTP") pilot program for LG&E's electric customers. The tam of the program shall be three **(3)** years. In each year, up to fifty (50) customers under Rate R and up to fifty (50) customers under Rate GS shall qualify for the program. During the second year of the program, LG&E shall propose to the Commission detailed plans, terms and conditions for the inclusion of customers under Rate LP in the program, such inclusion to take place during the second year of the program. Rate LP customers shall be eligible for participation in the program during the second and third years of the program in accordance with the Commission's approval of LG&E's proposal for inclusion of Rate LP customers. The customer-specific costs shall be recovered through a facilities charge incorporated into the applicable customer charges during the first six *(6)* months of the RTP pilot program. **After** six (6) months, the Utilities shall evaluate the level of participation in the pilot program and consider modifymg the treatment of such customer-specific charges to encourage participation in the RTP pilot program. The non customer-specific costs of modifying LG&E's customer billing system to bill customers under the RTP pilot program will be recovered pursuant to the RTP pilot program through a charge per kWh billed to customers taking service under Rates R, GS and LP in the same manner as the Demand-Side

Management ("DSM) Cost Recovery Component of LG&E's DSM Cost Recovery Mechanism. After the end of the three year term, LG&E will evaluate the performance of the RTP pilot program for the following purposes, including, but not limited to: (i) to determine the impact of the pilot program on its affected customers; (ii) to determine the amount of revenue loss from the pilot program, if any; (iii) to evaluate customer acceptance of the real time pricing program and (iv) to evaluate the potential for implementing the RTP program as either a permanent demand-side management program or as a standard rate schedule. LG&E shall file a report with the Commission describing its findings within six months after the first three years of implementation of the RTP pilot program. The RTP pilot program shall remain in effect until the program is modified or terminated by order of the Commission.

Section 3.7. The signatories hereto, including the AG, agree that the notice period for an Operational Flow Order pursuant to LG&E's Rate FT shall be twenty-four **(24)** hours.

Section 3.8. The signatories hereto, including the **AG,** agree that the miscellaneous charges of the Utilities shall be approved as proposed by the Utilities in the rate proceedings, except as follows: (i) the Disconnect-Reconnect Charge for LG&E electric customers, LG&E gas customers and KU electric customers shall be $20.00; and (ii) the KU After-Hours Reconnect Charge shall be withdrawn.

Section 3.9. The signatories hereto, including the AG, agree that the following monthly customer charges shall be implemented: (i) LG&E electric residential customers, $5.00 per month; (ii) LG&E gas residential customers, $8.50 per month; (iii) KU residential customers, $5.00 per month; (iv) LG&E GS electric single phase, $10.00 per month; (v) LG&E GS electric three phase, $15.00 per month; (vi) KU GS primary, $10.00 per month; and (vii) KU GS secondary, $10.00 per month. All other customer charges shall be implemented as proposed by the Utilities in their Applications filed on December 29,2003 in the rate proceedings.

Section 3.10. The signatories hereto, including the **AG,** agree that, for both LG&E and KU, Rate GS shall be available to electric customers with connected loads up to 500 kW.

Section 3.11. The signatories hereto, including the AG, agree that LG&E shall withdraw its Standard Riders for Summer **Air** Conditioning Service for its gas operations, and that customers served thereunder shall take service under otherwise applicable rate schedules.

Section 3.12. The signatories hereto, including the AG, agree that LG&E shall not bill an additional customer charge to Rate GS customers formerly taking service under the Rider for Electric Space Heating Service under Rate GS.

Section 3.13. The signatories hereto, including the AG, agree that LG&E shall eliminate the seasonal rate structure for Rate RS and shall implement a non-seasonally differentiated rate structure for Rate RS. Nothing contained in this Section shall preclude the Utilities from making a future proposal for a seasonal rate structure.

Section 3.14. The signatories hereto, including the AG, agree that, in conjunction with the AG, KACA, CAC, MHNA, and POWER, the Utilities will file plans for program administration with the Commission for year-round Home Energy Assistance ("HEA") programs in both of their respective service territories based solely upon a ten-cent per residential meter **per** month charge (the "HEA charge") for a period of three years. The HEA charge will be collected in the same manner as the DSM Cost Recovery Component of the Utilities' DSM Cost Recovery mechanism. The HEA programs shall be operated by existing social service providers ("Providers") with experience operating low-income energy assistance programs, who shall be entitled to recover actual operating expenses not to exceed ten percent (10%) of total HEA funds collected.

The signatories hereto, including the AG, agree that each HEA program will be subject to an outside independent annual audit conducted by an independent certified public accountant, in accordance with the Providers' existing audit requirements. Each audit shall include a detailed accounting of all expenses associated with administration of the program, which shall be **filed** annually with the Commission.

The signatories hereto, including the AG, further agree that KU shall be permitted recovery of its one-time information technology implementation costs through its DSM mechanism.

Section 3.15. The signatories hereto, including the AG, agree that the HEA programs to be filed shall have a commencement date of October 1,2004. Approval of this Settlement Agreement by the Commission shall constitute approval of the HEA parameters as proposed herein, subject to further review by the Commission of additional programmatic details. No money shall be distributed to the Providers pursuant to the HEA programs, or allocated pursuant to such programs, until such time as the Commission has issued final approval of the programmatic details.

Section 3.16. Within ninety days of the conclusion of the second year of the program, the Providers shall file with the Commission comprehensive program assessments to insure that the programs are meeting their respective established goals. Based upon those filings, and public hearings, if any, relating thereto, the Commission will then determine whether the HEA programs shall continue beyond three years and, if so, whether any modifications should be made to those programs.

Section 3.17. The signatories hereto, including the AG, who are parties to the respective Franklin Circuit Court actions hereby agree that upon approval of this Settlement Agreement by the Commission, they will jointly move the Franklin Circuit Court for the entry of an order dismissing the pending HEA and Pay As You Go ("PAYG") appeals, Civil Action Nos. 02-CI-00991 and 03-CI-00634, respectively.

Section 3.18. The signatories hereto, including the AG, agree that LG&E will phase out its PAYG program by limiting the program to existing customers and by removing those meters from existing customers as requested. as meters fail, or as customers move off the system. However, LG&E reserves the right to completely terminate the program upon sixty days advance notice to the Commission. LG&E and KU further agree that they will not seek approval of new prepaid metering programs for a period of at least five years from the date hereof, and that, after five years, approval by the Commission will be a necessary prerequisite to operating any new prepaid metering program.

Section 3.19. The signatories hereto, including the AG, agree that OMU NOx expenditures of $1 million per year incurred by KU pursuant to its contract with Owensboro Municipal Utility shall be recovered in KU's Environmental Cost Recovery filings pursuant to KRS 278.183. Recovery of the foregoing costs shall begin in April 2005 based upon the February 2005 expense month for KU.

Section 3.20. The signatories hereto, including the AG, agree that LG&E and KU shall offer a Curtailable Service Rider ("CSR1") to current customers who meet the eligibility requirements set forth in the proposed CSR1 tariff on such terms and conditions as specified in the proposed tariff subject to the following terms and conditions: (1) the customers shall be subject to curtailment for 250 hours annually; (2) the amount of the credit shall be $3.20 per kW for primary voltage customers and $3.10 per kW for transmission voltage customers; (3) the customers shall be entitled to 20 minutes notice of curtailment; (4) current customers shall have the option of buying through the curtailment at the market rate as determined by LG&E/KU; *(5)* in the event a customer elects to buy through a curtailment, the customer shall be required to purchase all of the demand to be curtailed on an hourly basis: and *(6)* this curtailable service rider is available only to those customers who are covered by an existing curtailable service rider as of the execution of this Settlement Agreement.

Section 3.21. The signatories hereto, including the AG, agree that new customers not currently served by an existing CSR will be eligible to take curtailable service under a new CSR tariff (CSR2) as originally filed by the Companies in the rate proceedings, except such customers will be able to buy through a request for curtailment only after having been on the CSR2 service for three years with no failure to curtail when requested.

Section 3.22. The signatories hereto, including the **AG,** agree that NAS's electric arc furnace operations shall receive electric service pursuant to the LI-TOD tariff, effective April 1, 2004, except as otherwise noted and which shall provide that the LI-TOD tariff shall be the same as the Non-Conforming Load Service Tariff ("NCLS") as proposed in Case No. 2003-00396 with the following changes:

(1) non-conforming load service shall be changed throughout to read large industrial-time of day (LI-TOD);

(2) the rates to be applied shall be the same rates applicable to customers on the LCI-TOD tariff;

(3) the demand charge shall he calculated by multiplying the rate established above by demand measured as Peak Demand **(KVA)** measured in 15 minute intervals plus the difference between Peak Demand measured in 5 minute intervals less Peak Demand measured in 15 minute intervals (if a positive number) multiplied by 0.5 times the rate, expressed as DC = [D15 +(D5-D15)0.5]R.

(4) Under the section of the tariff entitled System Contingencies and Industry System Performance Criteria the following additions are agreed:

a. The third sentence thereof shall be amended to limit the number of interruptions **per** month to no more than twenty with no carry-over from month to month. Within sixty days of the end of the applicable hilling period, upon request, information and documentation necessary for customer to verify that interruptions were caused by system contingencies as defined herein will be made available to customer;

b. Customers under the LI-TOD tariff may contract to curtail service upon notification by Company on the same terms and conditions as exist under the Curtailable Service Rider for LCI-TOD customers except requests for curtailment by the Companies shall not exceed 200 hours in the first year the Customer contracts for service, effective April 1, 2004, and 100 hours in each continuously succeeding year. Requests for curtailment shall he limited to on-peak periods specified in the LCI-TOD tariff.

c. All other provisions of the curtailable service rider as proposed in this Settlement Agreement for customers on the LCI-TOD tariff shall apply except that Customer may not buy through a request for curtailment by virtue of the unusual nature of the load of the Large Industrial class of customers.

d. System contingencies shall be defined in the tariff as:

In order to facilitate Company compliance with system contingencies and with NERC/ECAR System Performance Criteria, Customer will permit the Company to install electronic equipment and associated real time metering to permit Company interruption up to 95% of the Customer's load under this tariff when the LG&E Energy LLC System ("LEC System") experiences an unplanned outage or de-rate of LEC System-owned or purchased generation, or when Automatic Reserve Sharing is invoked within the ECAR or an ISO/RTO. LEC System as used herein shall consist of Company and Louisville Gas and Electric Company. Such equipment will electronically notify customer five (5) minutes before the electronically initiated interruption that will begin immediately thereafter and last no longer than ten (10) minutes. The interruptions will not be accumulated and credited against the annual curtailment hours under this contract.

(5) Customers covered by the LI-TOD tariff as of **April 1**, 2004 shall have the option to contract for additional service for a period of not less

than five (5) years under the terms of the tariff by signing a contrzct for additional service by March 1, 2005 which commits service to begin, or to pay, demand charges as agreed in such contract no later than July 1, 2006 before the tariff is extended to other customers. If the option given to current customers herein is not exercised by the dates specified the option expires.

(6) The difference. if any, between the invoiced charges for electric service for the NAS electric arc furnace operations for the months of April, May, and June, 2004 actually paid by NAS and those charges ultimately billed as approved by the Commission shall be refunded to NAS as a billing credit going forward.

Section 3.23. The signatories hereto, including the AG, agree that, except as modified in this Settlement Agreement, the proposals of the Utilities in the rate proceedings shall be approved as filed.

ARTICLE IV. Miscellaneous Provisions.

Section 4.1. The signatories hereto, including the AG, agree that making this Settlement Agreement shall not be deemed in any respect to constitute an admission by any party hereto that any computation, formula, allegation, assertion or contention made by any other party in these proceedings is true or valid.

Section 4.2. The signatories hereto, including the AG, agree that the foregoing stipulations and agreements represent a fair, just and reasonable resolution of the issues addressed herein and request the Commission to approve the Settlement Agreement.

Section4.3. The signatories hereto, including the AG, agree that, following the execution of this Settlement Agreement, the signatories shall cause the Settlement Agreement to be filed with the Commission by May 11, 2004, together with a request to the Commission for consideration and approval of this Settlement Agreement.

Section 4.4. The signatories hereto, other than the Utilities and the AG, stipulate that they will withdraw the direct testimony of their witnesses in the rate proceedings. The signatories hereto, other than the AG, stipulate that they will not otherwise contest the Utilities' proposals in the rate proceedings regarding the subject matter of the Stipulation, and that they will refrain from cross-examination of the Utilities' witnesses during ihe rate proceedings, except insofar as such cross-examination is in support of the Stipulation.

Section 4.5. The signatories hereto, including the AG, agree that this Settlement Agreement is subject to the acceptance of and approval by the Public Service Commission. The signatones hereto, including the AG, further agree to act in good faith and to use their best efforts to recommend to the Commission that this Settlement Agreement be accepted and approved.

Section 4.6. The signatories hereto, including the **AG,** agree that, if the Commission does not accept and approve this Settlement Agreement in its entirety, then: (a) this Settlement Agreement shall be void and withdrawn by the parties hereto from further consideration by the Commission and none of the parties shall be bound by any of the provisions herein. provided that no party is precluded from advocating any position contained in this Settlement Agreement; and (b) neither the terms of this Settlement Agreement nor any matters raised during the settlement negotiations shall be binding on any of the signatones to this Settlement Agreement or be construed against any of the signatories.

Section 4.7. The signatories hereto, including the AG, agree that, should the Settlement Agreement be voided or vacated for any reason after the Commission has approved the Settlement Agreement, then the parties shall be returned to the ***status*** *quo* existing at the time immediately prior to the execution of this agreement.

Section **4.8.** The signatories hereto, including the AG, agree that this Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

Section4.9. The signatories hereto, including the AG, agree that this Settlement Agreement shall inure to the benefit of and be binding upon the parties hereto, their successors and assigns.

Section 4.10. The signatories hereto, including the AG, agree that this Settlement Agreement constitutes the complete agreement and understanding among the parties hereto, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

Section 4.11. The signatories hereto, including the AG, agree that, for the purpose of this Settlement Agreement only, the terms are based upon the independent analysis of the parties to reflect a fair, just and reasonable resolution of the issues herein and are the product of compromise and negotiation.

Section 4.12. The signatories hereto, including the AG, agree that neither the Settlement Agreement nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Settlement Agreement. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

Section 4.13. The signatories hereto, including the AG, warrant that they have informed, advised, and consulted with the respective parties hereto in regard to the contents and significance of this Settlement Agreement and based upon the foregoing are authorized to execute this Settlement Agreement on behalf of the parties hereto.

Section 4.14. The signatories hereto, including the AG, agree that this Settlement Agreement is a product of negotiation among all parties hereto, and no provision of this Settlement Agreement shall be strictly construed in favor of or against any party. Notwithstanding anything contained in the Settlement Agreement, the parties recognize and agree that the effects, if any, of any future events upon the operating income of the Utilities are unknown and this Settlement Agreement shall be implemented as written.

Section **4.15.** The signatories hereto, including the AG, agree that this Settlement Agreement may be executed in multiple counterparts.

IN WITNESS WHEREOF, the parties hereto have hereunto affixed their signatures.

Louisville Gas and Electric Company
and Kentucky Utilities Company

HAVE SEEN AND AGREED:

By: ______________________
Kendrick R. Riggs, Counsel

-and-

By: ______________________
Dorothy E. O'Brien. Counsel

Commonwealth of Kentucky, **ex.** rel. Gregory Stumbo, Attorney General, by and through the **Office** of Rate Intervention

HAVE SEEN **AND** AGREED:

By: ____________________
Elizabeth E. Blackford, Counsel

Kentucky Industrial Utility Customers, Inc.

HAVE SEEN AND AGREED:

By:____________________________

David F. Roehm, Counsel

Michael L. Kurtz, Counsel

Commonwealth of Kentucky,
Environmental and Public Protection Cabinet,
Division of Energy

HAVE SEEN AND AGREED:

By:______________________________
Iris Skidmore, Counsel

United States Department of Defense

HAVE SEEN AND AGREED:

By: Peter B. [signature]
for David A. McCormick, Counsel

The Kroger Co.

HAVE SEEN AND AGREED:

By: ______________________________

David C. Brown, Counsel

Kentucky Association for Community
Action, Inc.

HAVE SEEN AND AGREED:

By:________________________________
Joe F. Childers, Counsel

Community Action Council for
Lexington-Fayettc, Bourbon, Harrison
and Nicholas Counties. Inc.

HAVE SEEN AND AGREED:

By: ______________________
Joe F. Childers, Counsel

Metro Human Needs Alliance

HAVE SEEN AND AGREED:

By: [signature]
Lisa Kilkelly, Counsel

People Organized and Working for Energy Reform

HAVE SEEN AND AGREED:

By: ______________________________
Lisa Kilkelly, Counsel

Lexington-Fayette Urban County Government

HAVE SEEN AND AGREED:

By: [signature]
David J. Barberie, Counsel

North American Stainless. L.P.

HAVE SEEN AND AGREED:

By: ______________________________
Richard S. Taylor, Counsel

By: ______________________________
Nathaniel K. Adams, Counsel

By: ______________________________
Kimberly S. McCann, Counsel

Kentucky Utilities Company
Summary of Proposed Electric Rate Increase by Rate Class
For the 12 months Ended September 30, 2002

	Adjusted Billings at Current Rates	Proposed Increase In Revenue Aa Filed	Percentage Increase	Settlement Increase	Percentage Increase	Increase as Percentage of Total
Residential	$ 252,910,745	$ 24,185,323	9.56%	$ 20,193,976	7.98%	43.763%
General Service	66,269,093	5,792,730	8.74%	$ 4,933,172	7.44%	10.691%
All Electric School Service Rate AES	3,955,546		0.00%	294,587	7.45%	0.638%
Combined Lighling & Power Service	226,957,349	18,885,564	8.32%	16,908,062	7.45%	36.642%
Comm./Industrial Time-of-Day	84,135,770	6,725,688	7.99%	2,048,936	2.44%	4.440%
Coal Mining Power Service	8,542,207	725.107	8.49%	638,188	7.47%	1.383%
Large Mine Power Time-of-Day	6,043,407	513.353	8.49%	453,462	7.50%	0.983%
Special Contract	14,551,478	(202,024)	-1.19%	(261.052)	-1.79%	-0.566%
Private Outdoor Lighling	13,396,416	1,179,334	8.80%	934,463	6.98%	2.025%
TOTAL ULTIMATE CONSUMERS	676,762,012	57,805,075	8.54%	46,143,794	6.82%	100.00%
Miscellaneous Service Revenue	999,716	1,003,763		408.443		
Rent from Electric Property	1,957,235	(556.373)		(556,373)		
TOTAL JURISDICTIONAL	679,718,963	58,252,465	8.57%	45,995,864	6.77%	

Kentucky Utilities Company
Summary of Proposed Increase
Based on Sales for the 12 Months Ended September 30.2003

	Adjusted Billings at Current Rates	Increase	Percentage Increase
Residential Rate RS	$ 121,233,915	$ 6,943,465	
Full Electric Residential Service Rate FERS	131,265,061	13.122.981	
Comb. Off-Peak Water Heating Rate CWH - RS	226.880	66.404	
Comb. Off-Peak Water Heating Rate CWH - FERS	184,889	61.127	
Total Residential	252.910,745	20.193.976	7.98%
General Service Rate *GS* - Secondary	63,054,553	4,464,741	
General Service Rate *GS* - Primary	2,543,978	233.163	
Comb. Off-Peak Water Heating Rate CWH - *GS*	2.434	798	
Electric Space Healing Rider - Rate 33	668.126	234,469	
Total General Service	66,269,093	4,933,172	7.44%
All Electric School Service Rate AES	3,955,546	294,587	7.45%
Combined Lighting 8 Power Service Rate LP - Secondary	155,582,998	12,488,035	
Combined Lighting 8 Power Service Rate LP - Primary	35,121,687	1.919.971	
Combined Lighting 8 Power Service Rate LP - Transmission	805.361	44,566	
Water Pumping Service Rate M	723,351	45,644	
High Load Factor Rate HLF Primary	22,475,293	1,496,550	
High Load Factor Rate HLF Secondary	12,248,660	913.296	
Total Combined Lighting & Power Service	226,957,349	16,908,062	7.45%
Large Comm./Industrial Time-of-Day Rate LCI-TOD Primary	65,546,566	1,621,297	
Large Comm./Industrial Time-of-Day Rate LCI-TOD Transmission	18,589,204	427.638	
Total Comm/Industrial Time-of-Day	84,135,770	2,048,936	2.44%
Coal Mining Power Service Rate MP Transmission	3,748,239	285.069	
Coal Mining Power Service Rate MP Primary	4,793,968	353.120	
Total Coal Mining Power Service	8,542,207	638.188	7.47%
Large Mine Power Time-of-Day Rate LMP-TOD Primary	1,944,714	148.303	
Large Mine Power Time-of-Day Rate LMP-TOD Transmission	4 098.693	305,159	
Total Large Mine Power Time-of-Day	6,043 407	453,462	7.50%
Special Contract	14,551,478	(261,052)	-1.79%
Street Lighting Service Rate St. Lt.	5,402,425	376,225	
Decorative Street Lighting Service Rate Dec. St. Lt.	807,559	56,815	
Private Outdoor Lighting Service Rate P.O. Lt.	6,293,269	438.616	
Customer Outdoor Lighting Service Rate C. O. Lt.	693,164	60.807	
Total Private Outdoor Lighting	13,396,416	934.463	6.98%
TOTAL ULTIMATE CONSUMERS	$ 676,762,012	$ 46,143,794	6.82%
Miscellaneous Service Revenue	999.716	408.443	
Rent from Electric Property	1,957,235	(556.373)	
TOTAL JURISDICTIONAL	679,718,963	45,995,864	6.77%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBEI 30.2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
RS - Rate Codes 010,050						
Customer Charges '(a)	2,708,953		$ 2.82	$ 7,639,247	$ 5.00	$ 13,544,765
First 100 KWH		260,463,182	$ 0.05017	13,067,438	$ 0.04404	11,470,799
Next 300 KWH		718,054,152	$ 0.04572	32,829,436	$ 0.04404	31,623,105
Next 600 KWH		913,350,525	$ 0.04172	38,104,984	$ 0.04404	40,223,957
Excess KWH		752,270,308	$ 0.04172	31,384,717	$ 0.04404	33,129,984
Sub-Total		2,644,138,167		$ 115,386,575		$ 116,447,845
Total Calculated at Base Rates				$ 123,025,822		$ 129.992.610
Correction Factor				0.999957		0.999957
Total After Application of Correction Factor				$ 123,031,152		$ 129,998,242
Fuel Clause Billings - proforma for rollin				1,946,159		1,946,159
Merger Surcredit				(2,974,607)		(2,974,607)
Value Delivery Surcredit				(367,155)		(367,155)
VDT Amortization & Surcredit Adjustment				15,547		15,547
Adjustment to Reflect Year-End Customers				(417,181)		(440.805)
Total Rate RS				$ 121,233,915		$ 128,177,380
Proposed Increase						6,943,465
Percentage Increase						5.73%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
CWH -Rate Code 120, RS						
Customer Charges '(a)	51,243		$ 1.03	$ 52,780		$
First 100 KWH		4,042,164	$ 0.02665	107,724	$ 0.04404	178,017
Next 300 KWH		2,852,289	$ 0.02665	76,013	$ 0.04404	125,615
Next 600 KWH		193,230	$ 0.02665	5,150	$ 0.04404	8,510
Excess KWH		0	$ 0.02665		$ 0.04404	
Subtotal		7,087,683		$ 188,887		$ 312,142
Total Calculated at Base Rates				$ 241,667		$ 312,142
Correction Factor				0.999750		0.999750
Total After Application of Correction Factor				$ 241,727		$ 312,220
Fuel Clause Billings - proforma for rollin				5,535		5,535
Merger Surcredit				(5,712)		(5,712)
Value Delivery Surcredit				(679)		(679)
VDT Amortization & Surcredit Adjustment				29		29'
Adjustment to Reflect Year-End Customers				(14,020)		(18,108)
Total Rate CWH / RS				$ 226,880		$ 293,284
Proposed Increase						66,404
Percentage Increase						29.27%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
FERS - Rate Codes 020,060,080						
Customer Charges "(a)	1,983,477		$ 3.85	$ 7,636,386	$ 5.00	$ 9,917,385
First 1,000 KWH		1,686,402,755	$ 0.04229	71,317,973	$ 0.04404	74,269,177
Excess KWH		1,358,217,822	$ 0.03836	52,101,236	$ 0.04404	59,815,913
Sub-Total		3,044,620,577		$ 123,419,208		$ 134,085,090
Total Calculated at Base Rates				$ 131,055,595		$ 144,002,475
Correction Factor				0.999917		0.999917
Total After Application of Correction Factor				$ 131,066,473		$ 144,014,428
Fuel Clause Billings - proforma for rollin				1,905,058		1,905,058
Merger Surcredit				(3,110,470)		(3,110,470)
Value Delivery Surcredit				(383,963)		(383,963)
VDT Amortization & Surcredit Adjustment				16,258		16,258'
Adjustment to Reflect Year-End Customers				1,771,704		1,946,729
Total Rate FERS				$ 131,285,061		$ 144,386,041
Proposed Increase						13.1 22,981
Percentage Increase						10.00%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
CWH - Rate Codes **122** FERS						
Customer Charges "(a)	36,730		$ 1.03	$ 37.832	$ -	$ -
First 1,000 KWH		5,846,032	$ 0.02665	155,797	$ 0.04404	257,459
Excess KWH		0	$ 0.02665		$ 0.04404	
Sub-Total		5,846,032		$ 155,797		$ 257,459
Total Calculated at Base Rates				$ 193.629		$ 257,459
Correction Factor				0.999892		0.999892
Total After Application of Correction Factor				$ 193,650		$ 257,487
Fuel Clause Billings - proforma for rollin				4,573		4,573
Merger Surcredit				(4,584)		(4,584)
Value Delivery Surcredit				(550)		(550)
VDT Amortization & Surcredit Adjustment				23		23
Adjustment to Reflect Year-End Customers				(8,223)		(10,934)
Total Rate CWH / FERS				**$ 104,009**		**$ 246,016**
Proposed increase						**61,127**
Percentage Increase						33.06%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
GSS - Rate Codes 110, 113, 150, 153, 710						
Customer Charges '(a)	822,782		$ 4.11	$ 3,381,634	$ 10.00	$ 8,227,820
First 500 KWH		250,675,964	$ 0.06443	16,151,052	$ 0.05327	13,353,509
Next 1,500 KWH		340,305,160	$ 0.05332	18,145,071	$ 0.05327	18,128,056
Excess KWH		514,894,841	$ 0.04870	25,075,379	$ 0.05327	27,428,448
Sub-Total		1,105,875,966		$ 59,371,502		$ 58,910,013
Total Calculated at Bare Rates				$ 62,753,136		$ 67,137,833
Correction Factor				0.994771		0.994771
Total After Application of Correction Factor				$ 63,083,006		$ 67,490,751
Fuel Clause Billings - proforma for rollin				831,532		831,532
Merger Surcredit				(1,498,838)		(1,498,838)
Value Delivery Surcredit				(184,691)		(184,691)
VDT Amortization & Surcredit Adjustment				7,821		7,821
Adjustment to Reflect Year-End Customers				815,724		872,720
Total Rate GS Secondary				$ 63,054,553		$ 67,519,294
Proposed Increase						4,464,741
Percentage Increase						7.08%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
GSP - Rate Codes 111, 151						
Customer Charges "(a)	1,127		$ 4.11	$ 4,632	$ 10.00	$ 11,270
First 500 KWH		461,154	$ 0.06443	29,712	$ 0.05327	24,566
Next 1,500 KWH		1,168,955	$ 0.05332	62,329	$ 0.05327	62,270
Excess KWH		50,497,087	$ 0.04870	2,459,208	$ 0.05327	2,689,980
Sub-Total		52,127,196		$ 2,551,249		$ 2,776,816
Primary Service Discounts				(142,440)		(155,381)
Minimum Billings				156,810		171,057
Total Calculated at Base Rates				$ 2,570,251		$ 2,803,762
Correction Factor				1.001490		1.001490
Total After Application of Correction Factor				$ 2,566,427		$ 2,799,590
Fuel Clause Billings - proforma for rollin				45,451		45,451
Merger Surcredit				(61,024)		(61,024)
Value Delivery Surcredit				(7,181)		(7,181)
VDT Amortization & Surcredit Adjustment				304		304
Adjustment to Reflect Year-End Customers				-		
Total Rate GS Primary				$ 2,543,978		$ 2,777,141
Proposed Increase						233,163
Percentage Increase						9.17%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
CWH -Rate Codes 126 GS						
Customer Charges '(a)	901		$ 1.03	$ 928		$
First 500 KWH		68,163	$ 0.02665	1,817	$ 0.05327	3,631
Next 1,500 KWH		342	$ 0.02665	9	$ 0.05327	18
Excess KWH		0	$ 0.02665		$ 0.05327	
Sub-Total		66,505		$ 1,826		$ 3,649
Total Calculated at Base Rates				$ 2,754		$ 3,649
Correction Factor				1.000019		1.000019
Total After Application of Correction Factor				$ 2,754		$ 3,649
Fuel Clause Billings - proforma for rollin				51		51
Merger Surcredit				(64)		(64)
Value Delivery Surcredit				(7)		(7)
VDT Amortization & Surcredit Adjustment				0		0
Adjustment to Reflect Year-End Customers				(299)		(396)
Total Rate CWH / GS				$ 2,434		$ 3,233
Proposed Increase						798
Percentage Increase						32.79%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2) Bills	(3) Total KWH	(4) Present Rates	(5) Calculated Revenue @ Present Rates (see Exhibit 9)	(6) Settlement Rates	(7) Calculated Revenue @ Proposed Rates
33 - Rate Code 330 GS						
Customer Charges *(a)	11,530		$ -	$	$ -	$
First 500 KWH		3,040,894	$ 0.03926	119,385	$ 0.05327	161,988
Next 1,500 KWH		4,522,308	$ 0.03926	177,546	$ 0.05327	240,903
Excess KWH		9,709,702	$ 0.03926	381,203	$ 0.05327	517,236
Sub-Total		17,272,904		$ 678,134		$ 920,128
Minimum Billings				23,562		23,562
Total Calculated at Base Rates				$ 701,696		$ 943,690
Correction Factor				1.002812		1.002812
Total After Application of Correction Factor				$ 699,728		$ 941,043
Fuel Clause Billings - proforma for rollin				6,006		6,006
Merger Surcredit				(15,915)		(15,915)
Value Delivery Surcredit				(1,924)		(1,924)
VDT Amortization & Surcredit Adjustment				81		81
Adjustment to Reflect Year-End Customers				(19,849)		(26,694)
Total Rate 33				$ 668,128		$ 902,598
Proposed Increase						234,469
Percentage Increase						35.09%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LPS/AES - Rate Coda 220						
Number of Customers	3.474					
Demand	367,906		$ -	$	$ -	$
First 500,000 KWH		100,707,601	$ 0.03936	3,963,851	$ 0.04227	4,256,910
Next 1,500,000 KWH		0	$ 0.03936		$ 0.04227	
Excess KWH		0	$ 0.03936		$ 0.04227	
Sub-Total		100,707,601		$ 3,963,851		$ 4,256,910
Minimum Billings				6,022		6,022
Total Calculated at Base Rates				$ 3.969.873		5 4,262,932
Correction Factor				0.994813		0.994813
Total After Application of Correction Factor				$ 3,990,570		$ 4,285,158
Fuel Clause Billings - proforma for rollin				70,235		70,235
Merger Surcredit				(94,157)		(94,157)
Value Delivery Surcredit				(11,594)		(11,594)
VDT Amortization & Surcredit Adjustment				491		491
Adjustment to Reflect Year-End Customers						
Total Rate AES				$ 3,955,546		$ 4,250,133
Proposed Increase						294,587
Percentage Increase						7.45%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2) Bills / KW	(3) Total KWH	(4) Present Rates	(5) Calculated Revenue @ Present Rates (see Exhibit 9)	(6) Settlement Rates	(7) Calculated Revenue @ Proposed Rates
LPS -Rate Codes **562,568**						
Number of Customers	154,715				$ 75.00	$ 11,603,625
Demand	10,678,854		$ 4.11	$ 43,890,092	$ 6.65	71,014,382
Minimum Annual Charges				136,444		220,767
First 500,000 KWH		3,874,329,937	$ 0.02872	111,270,756	$ 0.02200	85,235,259
Next 1,500,000 KWH		61,080,231	$ 0.02633	1,608,242	$ 0.02200	1,343,765
Excess KWH		0	$ 0.02504		$ 0.02200	
Sub-Total		3,935,410,168		$ 112,878,998		$ 86,579,024
Total Calculated at Base Rates				$ 156,905,534		$ 169,417,797
Correction Factor				0.998130		0.998130
Total After Application of Correction Factor				$ 157,199,484		$ 169,735,188
Fuel Clause Billings - proforma for rollin				3,170,805		3,170,805
Merger Surcredit				(3,748,979)		(3,748,979)
Value Delivery Surcredit				(460,016)		(460,016)
VDT Amortization & Surcredit Adjustment				19,479		19,479
Adjustment to Reflect Year-End Customers				(597,774)		(645,443)
Total Rate LP Secondary				$ **155,582,998**		**$ 168,071,034**
Proposed Increase						**12,488,035**
Percentage Increase						8.03%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills/ KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LPP - Rate Codes **561,566**						
Number of Customers	3,656				$ 75.00	$ 274,200
Demand	2,381,439		$ 3.13	$ 7,453,905	$ 6.26	14,907,810
CSR Credits	43,289		$ (3.20)	(138,526)	$ (3.20)	(138,526)
CSR Penalties				2,411		2,411
First 500,000 KWH		639,927,383	$ 0.02872	18,378,714	$ 0.02200	14,078,402
Next 1,500,000 KWH		331,775,188	$ 0.02633	8,735,641	$ 0.02200	7,299,054
Excess KWH		26,286,146	$ 0.02504	658,205	$ 0.02200	578,295
Sub-Total		997,988,716		$ 27,772,560		$ 21,955,752
Total Calculated at Base Rates				$ 35,090,351		$ 37,001,647
Correction Factor				0.998820		0.998820
Total After Application of Correction Factor				$ 35,131,814		$ 37,045,369
Fuel Clause Billings - proforma for rollin				814,739		814,739
Merger Surcredit				(843,553)		(843,553)
Value Delivery Surcredit				(103,491)		(103,491)
VDT Amortization & Surcredit Adjustment				4,382		4,382
Adjustment to Reflect Year-End Customers				117,795		124,211
Total Rate **LP** Primary				**$ 35,121,687**		**$ 37,041,656**
Proposed Increase						**1,919,971**
Percentage Increase						5.47%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills/ KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LPT - Rate Codes 560,567						
Number of Customers	27				$ 75.00	$ 2,025
Demand	36.408		$ 2.97	$ 108.133	$ 5.92	215,538
Minimum Annual Charges				1,522		3,034
First 500,000 KWH		6,109,950	$ 0.02872	175,478	$ 0.02200	134,419
Next 1.500.000 KWH		9,366,902	$ 0.02633	246,631	$ 0.02200	206,072
Excess KWH		0	$ 0.02504		$ 0.02200	
Sub-Total		15,476,852		$ 422,108		$ 340,491
Total Calculated at Base Rates				$ 531,763		$ 561.087
Correction Factor				0.993946		0.993946
Total Afler Application of Correction Factor				$ 535,002		$ 564,505
Fuel Clause Billings - proforma for rollin				11,436		11,436
Merger Surcredit				(12,742)'		(12,742)
Value Delivery Surcredit				(1,567)		(1,567)
VDT Amortization & Surcredit Adjustment				66'		66
Adjustment to Reflect Year-End Customers				273,166		288,230
Total Rate LP Transmission				$ **805,361**		$ **849,927**
Proposed Increase						**44,566**
Percentage Increase						5.53%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LCIP - Rate Code 563						
Number of Customers	315				$ 120.00	$ 37.800
On-Peak Demand	4,068,204		$ 4.14	$ 16,842,364	$ 4.58	18,632,374
Off-Peak Demand	3,969,563		$ 0.73	$ 2,897,781	$ 0.73	2,897,781
CSR Credits	64.834		$ (3.20)	$ (207,469)	$ (3.20)	(207,469)
Penalties				21,553		21,553
Energy		2,080374,735	$ 0.02210	45,987,332	$ 0.02200	45,779,244
Total Calculated at Base Rates				$ 65,541,561		$ 67,161,283
Correction Factor				0.999029		0.999029
Total After Application of Correction Factor				$ 65,605,294		$ 67,226,592
Fuel Clause Billings - proforma for rollin				1,698,726		1,698,726
Merger Surcredit				(1,573,353)		(1,573,353)
Value Delivery Surcredit				(192,241)		(192,241)
VDT Amortization & Surcredit Adjustment				8,140		8,140
Adjustment to Reflect Year-End Customers						
Total Rate LCI Primary				$ 65,546,566		$ 67,167,863
Proposed Increase						1,621,297
Percentage increase						2.47%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
EASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LCIT - Rate Code 564						
Number of Customers	48				$ 120.00	$ 5,760
On-Peak Demand	1,099,952		$ 3.95	$ 4,344,810	$ 4.39	4,828,789
Off-Peak Demand	1,092,494		$ 0.73	797.521	$ 0.73	797,521
CSR Credits	122.014		$ (3.10)	(378,243)	$ (3.10)	(378,243)
Penalties				76,807		76,807
Energy		621,047,926	$ 0.02210	13,725,159	$ 0.02200	13,663,054
Total Calculated at Base Rates				$ 18,566,054		$ 18,993,688
Correction Factor				0.999990		0.999990
Total After Application of Correction Factor				$ 18,566,238		$ 18,993,876
Fuel Clause Billings - proforma for rollin				526,690		526,690
Merger Surcredit				(450,942)		(450,942)
Value Delivery Surcredlt				(55,117)		(55,117)
VDT Amortization & Surcredit Adjustment				2,334		2,334
Adjustment to Reflect Year-End Customers						
Total Rate LCI Transmission				$ 18,589,204		$ 19,016,842
Proposed Increase						427,630
Percentage Increase						2.30%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
HLFP - Rate Code 571						
Number of Customers	529				$ 75.00	$ 39,675
Demand	1,345,913		$ 4.79	$ 6,446,922	$ 6.26	8,425,414
Energy		723,323,088	$ 0.02270	16,419,434	$ 0.02200	15,913.108
Minimum Billings				38,375		50,151
Total Calculated at Base Rates				$ 22.904.731		$ 24.428.349
Correction Factor				0.994328		0.994328
Total After Application of Correction Factor				$ 23,035,385		$ 24,567,694
Fuel Clause Billings - proforma for rollin				591,757		591,757
Merger Surcredit				(550,321)		(550,321)
Value Delivery Surcredit				(66,795)		(66,795)
VDT Amortization & Surcredit Adjustment				2,828		2,828
Adjustment to Reflect Year-End Customers				(537,561)		(573,319)
Total Rate HLF Primary				$ **22,475,293**		**$ 23,971,843**
Proposed Increase						**1,496,550**
Percentage Increase						6.66%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
HLFS - Rate Code 572						
Number of Customers	494				$ 75.00	$ 37,050
Demand	705,460		$ 5.13	$ 3,619,007	$ 6.65	4,691,306
Energy		370,430,550	$ 0.02270	8,408,773	$ 0.02200	8,149,472
Minimum Billings				203,871		264,277
Total Calculated at Base Rates				$ 12,231,651		5 13,142,105
Correction Factor				0.996888		0.996888
Total After Application of Correctlon Factor				$ 12,269,841		$ 13,183,137
Fuel Clause Billings - proforma for rollin				305,857		305,857
Merger Surcredit				(292,805)		(292,805)
Value Delivery Surcredit				(35,747)		(35,747)
VDT Amortization & Surcredit Adjustment				1,514,		1,514
Adjustment to Reflect Year-End Customers						-
Total Rate HLF Secondary				5 12,248,660		$ 13,161,955
Proposed Increase						913.296
Percentage Increase						7.46%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Rate M - Rate Code 650						
Customer Charges '(a)	1,151		$ 10.27	$ 11,821	$ 75.00	$ 86,325
Demand Charges	46,351.6		$ -	$	$ 6.65	$ 308,238
First 10,000 KWH		6.1 36,374	$ 0.04631	284.175	$ 0.02200	135,000
Excess KWH		10,959,266	$ 0.03917	429,274	$ 0.02200	241,104
Sub-Total		17,095,640		$ 713,450		$ 376,104
Total Calculated at Base Rates				$ 725,271		$ 770,667
Correction Factor				0.994581		0.994581
Total After Application of correction Factor				$ 729,223		$ 774,866
Fuel Clause Billings - proforma for rollin				13,459		13,459
Merger Surcredit				(17,302)		(17,302)
Value Delivery Surcredit				(2,118)		(2,118)
VDT Amortization & Surcredit Adjustment				90'		90
Adjustment to Reflect Year-End Customers						
Total Rate M Water Pumping				$ 723,351		$ 768,995
Proposed Increase						45,644
Percentage Increase						6.31%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
EASED ON SALES FOR THE **12** MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
MPT - Rate Codes **680,687**						
Number of Customers	183				$ 75.00	$ 13,725
Demand	335,459		$ 2.67	$ 895.675	$ 4.57	1,533,046
First 500,000 KWH		55,158,510	$ 0.02881	1,589.117	$ 0.02400	1,323,804
Excess KWH		59,532,090	$ 0.02540	1,512,115	$ 0.02400	1,428,770
Sub-Total		114,690,600		$ 3,101,232		$ 2,752.574
Total Calculated at Base Rates				$ 3,996,906		$ 4,299,346
Correction Factor				0.988697		0.988697
Total After Application of Correction Factor				$ 4,042,601		$ 4,348,498
Fuel Clause Billings - proforma for rollin				87.711		87,711
Merger Surcredit				(95,856)		(95,656)
Value Delivery Surcredit				(11,653)		(11,653)
VDT Amortization & Surcredit Adjustment				493		493
Adjustment to Reflect Year-End Customers				(275,257)		(296,085)
Total Rate MP **Transmission**				**$ 3,746,239**		**$ 4,033,308**
Proposed Increase						**285,069**
Percentage Increase						7.61%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
MPP - Rate Codes 681,686						
Number of Customers	261				$ 75.00	$ 19,575
Demand	473.781		$ 3.01	$ 1,428,082	$ 4.69	2,222,034
First 500,000 KWH		89,036,933	$ 0.02881	2,565,154	$ 0.02400	2,136,886
Excess KWH		38,740,167	$ 0.02540	984,000	$ 0.02400	929,764
Sub-Total		127,777,100		$ 3,549,154		$ 3,086,650
Minimum Annual Charges				64,223		100,068
Total Calculated at Base Rates				$ 5,039,459		$ 5,408,328
Correction Factor				0.996149		0.996149
Total After Application of Correction Factor				$ 5,058,939		$ 5,429,234
Fuel Clause Billings - proforma for rollin				103.480		103,480
Merger Surcredit				(119,812)		(119,812)
Value Delivery Surcredit				(14,613)		(14,813)
VDT Amortization & Surcredit Adjustment				619'		619
Adjustment to Reflect Year-End Customers				(234,645)		(251,820)
Total Rate MP Primary				$ 4,793,968		$ 5,147,088
Proposed Increase						353,120
Percentage Increase						7.37%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement 'Rates	Calculated Revenue @ Proposed Rates
LMPP - Rate Code 683						
Number of Customers	25				$ 120.00	$ 3,000
On-Peak Demand	160,687		$ 4.14	$ 665,243	$ 5.39	866,102
Off-Peak Demand	160,665		$ 0.73	117,266	$ 0.73	117,286
Energy		56,287,872	$ 0.02094	1,178,668	$ 0.02000	1,125,757
Minimum Annual Billings				(8,760)		(11,405)
Total Calculated at Base Rates				$ 1,952,437		$ 2,100,740
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 1,952,437		$ 2,100,740
Fuel Clause Billings - proforma for rollin				43.817		43,817
Merger Surcredit				(46,196)		(46,196)
Value Delivery Surcredit				(5,581)		(5,581)
VDT Amortization & Surcredit Adjustment				236		236
Adjustment to Reflect Year-End Customers						
Total Rate LMP Primary				**$ 1,944,714**		**$ 2,093,017**
Proposed Increase						**148,303**
Percentage Increase						7.63%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
LMPT - Rate Code 664						
Number of Customers	82				$ 120.00	$ 9,840
On-Peak Demand	400,744		$ 3.80	$ 1,522,827	$ 4.85	1,943,608
Off-Peak Demand	381,990		$ 0.73	278,853	$ 0.73	278,853
Energy		135,342,000	$ 0.02094	2,834,061	$ 0.02000	2,706,840
Minimum Annual Billings				197,968		252,670
Total Calculated at Base Rates				$ 4,833,710		$ 5,191,811
Correction Factor				1.002250		1.002250
Total Afler Application of Correction Factor				$ 4,822,860		$ 5,180,158
Fuel Clause Billings - proforma for rollin				106,921		106,921
Merger Surcredit				(114,208)		(114,208)
Value Delivery Surcredit				(13,680)		(13,680)
VDT Amortization & Surcredit Adjustment				579'		579
Adjustment to Reflect Year-End Customers				(703,778)		(755,917)
Total Rate LMP Transmission				$ 4,098,693		$ 4,403,852
Proposed Increase						305,159
Percentage Increase						7.45%
Total LMP				$ 6,043,407		$ 6,496,869
Proposed Increase						453.462
Percentage Increase						7.50%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Special Contract - Rate Code **720**						
Non-Interruptible Demand	408,840		$ 3.89	$ 1,590,387	$ 3.98	$ 1,627,182
Interruptible Demand			$ 1.86		$ 1.95	
Energy		256,027,222	$ 0.02148	5,499,465	$ 0.02200	5,632,599
Total Calculated at Base Rates				$ 7,089,852		$ 7,259,781
Correction Factor				1.000241		1.000241
Total After Application of Correction Factor				$ 7,088,146		$ 7,258,034
Fuel Clause Billings - proforma for rollin				206.387		206.387
Merger Surcredit				(170,246)		(170,246)
Value Delivery Surcredit				(20,695)		(20,695)
VDT Amortization & Surcredit Adjustment				876		876
Adjustment to Reflect Year-End Customers						
Total **WestVaCo** Special Contract				**$ 7,104,468**		**$ 7,274,357**
Proposed Increase						**169,889**
Percentage increase						2.39%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KVA KW	Total KWH	Present Rates	Calculated Revenue @ Present NCL Rate (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Special Contract Billing Code 723,724,725,726						
Non-Interruptible/On-Peak Deme	962,182		$ 5.58	$ 5,368,976	$ 4.39	$ 4,223,979
Interruptible/Off-Peak Demand	987,308		$ 1.03	$ 1,016,927	$ 0.73	$ 720,735
CSR Credit	887,629		$ (3.10)	$ (2,751,649)	$ (3.10)	$ (2,751,649)
Energy		224,499,600	$ 0.01750	3,928,743	5 0.02200	4,938,991
Total Calculated at Base Rates				$ 7,562,997		$ 7,132,056
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 7,562,997		$ 7,132,057
Fuel Clause Billings - proforma for rollin				200,577		200,577
Merger Surcredit				(283,568)		(283,568)
Value Delivery Surcredit				(34,456)		(34,456)
VDT Amortization & Surcredit Adjustment				1,459		1,459
Adjustment to Reflect Year-End Customers						
Total NAS Special Contract				$ 7,447,010		$ 7,016,069
Proposed increase						(430,941)
Percentage Increase						-5.79%

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
FWP - Rate Code 740 *(c)						
Energy		0	$ 0.03598		$ 0.03598	
Total Calculated at Base Rates						
Correction Factor						
Total After Application of Correction Factor						
INCREASE IN BASE RATES REVENUE						

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Street Lighting	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates	Settlement Rates	Calculated Revenue @ Proposed Rates
Incandescent Street Lighting (1)				(see Exhibit 9)		
I-1000-std	42,730	1,203	$ 2.11	$ 2,538	$ 2.26	$ 2,719
I-2500-std	1,293,398	18,532	$ 2.57	47,627	$ 2.75	50,963
I-4000-std	768.860	7,034	$ 3.68	25,885	$ 3.94	27,714
I-6000-std	12,762	84	$ 4.89	411	$ 5.24	440
I-10000-std	0	0	$ 6.57		$ 7.03	
I-1000-orn	0	0	$ 2.72		$ 2.91	
I-2500-orn	6,432	96	$ 3.32	319	$ 3.55	341
I-4000-orn	58,859	540	$ 4.56	2,462	$ 4.88	2,635
I-6000-orn	7,152	48	$ 5.07	282	$ 6.29	302
I-10000-orn	0	0	$ 8.07		$ 8.64	
Mercury Vapor Street Lighting						
MV-3500-std	0	0	$ 5.36		$ 6.60	
MV-7000-std	1,199,867	17,126	$ 6.19	106,010	$ 6.63	113,545
MV-10000-std	1,220,047	12,442	$ 7.14	88.836	$ 7.64	95,057
MV-20000-std	3,216,852	20,879	$ 8.39	175,175	$ 8.98	187,493
MV-3500-orn	0	0	$ 7.60		$ 8.14	
MV-7000-orn	102,988	1,492	$ 8.30	12,384	$ 8.89	13,264
MV-10000-orn	674,672	6,882	$ 9.01	62,007	$ 9.65	66,411
MV-20000-orn	2,851,854	18,790	$ 9.89	185,833	$ 10.59	198,986

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Street Lighting -continued	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates	Settlement Rates	Calculated Revenue @ Proposed Rates
High Pressure Sodium Street Lighting				(see Exhibit 9)		
HPS-4000-std	1,706,461	84.016	$ 4.68	393,195	$ 5.00	420.080
HPS-5800-std	2,821,602	97,770	$ 5.08	496.672	$ 5.43	530.891
HPS-9500-std	8,471,266	211,989	$ 5.72	1,212,577	$ 6.11	1,295,253
HPS-22000-std	4,975,937	60,024	$ 8.44	506,603	$ 9.02	541,416
HPS-50000-std	1,435,313	8,864	$ 13.62	120,728	$ 14.55	128,971
HPS-4000-orn	953,042	47,651	$ 7.13	339,752	$ 7.62	363,101
HPS-5800-orn	2,927,333	105,857	$ 7.53	797,103	$ 8.04	851,090
HPS-9500-orn	1,092,981	27,793	$ 8.35	232,072	$ 8.92	247,914
HPS-22000-orn	3,822,835	47,250	$ 11.06	522,585	$ 11.81	558,023
HPS-50000-orn	827,689	5,095	$ 16.23	82,692	$ 17.34	88.347
Sub-Total	40,490,932	801,457		$ 5,413,746		$ 5,784,957
Partial Month billings				86,450		92,378
Total Calculated at Base Rates				$ 5,500,195		$ 5,877,334
Correction Factor				1.000190		1.000190
Total After Application of Correction Factor				$ 5,499,149		$ 5,876,216
Fuel Clause Billings - proforma for rollin				30,519		30,519
Merger Surcredit				(129,056)		(129,056)
Value Delivery Surcredit				(15,744)		(15,744)
Adjustment to Reflect Year-End Customers				16.889		18.047
VDT Amortization & Surcredit Adjustment				667		667
Total Rate St. Lt.				$ 5,402,425		$ 5,780,650
Proposed increase						378,225

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

(1)	(2)	(3)	(4)		(5)	(6)		(7)
	KWH	Total Lights		Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)		Settlement Rates	Calculated Revenue @ Proposed Rates
Street Lighting-- Decorative								
HPS-A-4000-Dec	0	0	$	9.74	$	$	10.40	$
HPS-A-5800-Dec	1,992	72	$	10.24	737	$	10.94	788
HPS-A-9500-Dec	48,347	1,231	$	10.87	13,381	$	11.61	14,292
HPS-A-4000-His	29,279	1,464	$	15.28	22,370	$	16.32	23,892
HPS-A-5800-His	11,621	420	$	15.77	6.623	$	16.85	7,077
HPS-A-9500-His	144,939	3,677	$	16.41	60,340	$	17.53	64,458
HPS-4000 col	130,976	6,556	$	6.42	42,090	$	6.86	44,974
HPS-5800 col	174,991	6,208	$	6.83	42.401	$	7.30	45,318
HPS-9500 col	371,159	9,455	$	7.40	69,967	$	7.90	74,695
HPS-5800 coa	0	0						
HPS-9500 coa	0	0						
HPS-5800 con	634,990	22,944	$	11.80	270,739	$	12.60	289.094
HPS-9500 con	173,631	4,452	$	14.05	62,551	$	15.01	66.825
HPS-22000 con	268,604	3,329	$	16.29	54,229	$	17.40	57,925
HPS-50000 can	157,439	939	$	21.09	19,804	$	22.53	21,156
HPS-16000 Granville	3,611	63	$	44.60	2,810	$	47.64	3,001
HPS-16000 Granville A	83.872	1,666	$	35.84	59,709'	$	38.28	63,774
HPS-16000 Granville B	12,666	256	$	58.78	15,048	$	62.79	16,074
HPS-16000 Granville C	19,859	399	$	39.50	15,761	$	42.19	16,834
HPS-16000 Granville D	2,103	45	$	41.12	1,850	$	44.92	2,021
HPS-16000 Granville E	649	13	$	42.24	549	$	46.14	600
HPS-16000 Granville F	3,500	70	$	56.94	3,986	$	62.21	4,355
HPS-16000 Granville G	6,093	122	$	55.32	6,749	$	59.09	7,209
HPS-16000 Granville H	0	0	$	40.70		$	44.48	
HPS-16000 Granville I	1,296	26	$	36.96	961	$	40.38	1,050
HPS-16000 Granville A1	8,946	179	$	51.66	9,247	$	55.18	9,877
HPS-16000 Granville B1	0	0	$	74.60		$	79.69	
HPS-16000 Granville E I	649	13	$	58.06	755	$	63.43	825

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER), 2003

(1)	)	(:	(4)	(5)	(6)	(7)
	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Street Lighting -- Decorative - continued						
HPS-16000 Granville A2	7,930	160	$ 51.66	8,266	$ 55.18	8.829
HPS-16000 Granville 83	2,101	42	$ 52.78	2,217	$ 56.38	2.368
HPS-16000 Granville G l	1,190	24	$ 55.32	1,328	$ 59.09	1,418
HPS-16000 Granville 82	11,773	236	$ 53.92	12,725	$ 58.91	13,903
Sub-Total	2,314,206	64,061		$ 807,191		$ 862.631
Partial Month billings				6,975		7,454
Total Calculated at Base Rates				$ 814,165		$ 870.085
Correction Factor				0.999016		0.999016
Total After Application of Correction Factor			141,960	$ 814,967		$ 870,942
Fuel Clause Billings - proforma for rollin				1,736		1,736
Merger Surcredit				(19,076)		(19,076)
Value Delivery Surcredit				(2,409)		(2.409)
Adjustment to Reflect Year-End Customers				12,240'		13.081
VDT Amortization & Surcredit Adjustment				102		102
Total Rate Dec St. Lt.				$ 807,559		$ 864,374
Proposed Increase						**56,815**

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Settlement Rates	Calculated Revenue @ Proposed Rates
Private Outdoor Lighting						
Standard (Served Overhead)						
MV-7000-OB	2,542,058	36,524	$ 7.12	$ 260,051	$ 7.61	$ 277,948
MV-20000-Cobr	1,214,151	8,012	$ 8.41	67,381	$ 8.98	11,948
HPS-5800-OB	70,769	2,534	$ 4.05	10,263	$ 4.33	10,972
HPS-9500-OB	13,810,099	350.344	$ 4.62	1,618,589	$ 4.94	1,730,699
HPS-22000-Cobr	1,268,099	15,631	$ 8.44	131,926	$ 9.02	140,992
HPS-50000-Cobr	4,403,511	27,021	$ 13.62	368,026	$ 14.55	393,156
Directional (Served Overhead)						
HPS-9500	4,431,410	112,584	$ 5.60	630,470	$ 5.98	673,252
HPS-22000	5,191,668	64,058	$ 7.93	507,980	$ 8.47	542,571
HPS-50000	13,251,698	81,371	$ 12.08	982,962	$ 12.90	1,049,686
Decorative (Served Underground)						
HPS-4000 coa decr	'478	24	$ 9.74	234	$ 10.40	250
HPS-5800 coa decr	3,464	120	$ 10.24	1,229	$ 10.94	1,313
HPS-9500 coa decr	76,594	1,961	$ 10.88	21,336	$ 11.62	22,787
HPS-4000 coa hist	19,923	996	$ 15.28	15.219	$ 16.32	16,255
HPS-5800 coa hist	11,318	410	$ 15.77	6,466	$ 16.85	6,909
HPS-9500 coa hist	222,699	5,706	$ 16.42	93,693	$ 17.54	100,083
HPS-5800 coa	0	0	$ 23.47		$ 25.07	
HPS-9500 coa	64,116	1,644	$ 24.09	39,604	$ 25.73	42,300
HPS-4000 col	12,719	636	$ 6.42	4,083	$ 6.86	4,363
HPS-5800 col	35,199	1,272	$ 6.83	8,688	$ 7.30	9,286
HPS-9500 col	509,423	13,046	$ 7.40	96,540	$ 7.90	103,063
HPS-5800 con	16,935	612	$ 11.80	7,222	$ 12.60	7.711
HPS-9500 con	90,992	2,341	$ 14.05	32,891	$ 15.01	35,138
HPS-22000 con	546,476	6,756	$ 16.29	110,055	$ 17.40	117,554
HPS-50000 con	1,624,326	10,033	$ 21.09	211,596	$ 22.53	226,043

KENTUCKY UTILITIES COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBEI 30,2003

(1)	(2) KWH	(3) Total Lights		(4) Present Rates		(5) Calculated Revenue @ Present Rates (see Exhibit 9)		(6) Settlement Rates		(7) Calculated Revenue @ Proposed Rates
Private Outdoor Lighting - continued										
Metal Halide Directional										
MH-12000	209,687	3,026	$	8.27		25,025	$	8.83		26,720
MH-12000-WP	47,049	679	$	10.10		6,858	$	10.79		7.326
MH-12000-MP	3,328	48	$	16.10		773	$	17.20		826
MH-32000	3,174,956	21,013	$	11.46		240,809	$	12.24		257,199
MH-32000-WP	759,074	5,025	$	13.30		66,833	$	14.21		71,405
MH-32000-MP	162,468	1,085	$	19.29		20,930	$	20.81		22,362
MH-107800	5,180,248	14,272	$	23.67		337,818	$	25.28		360,796
MH-107800-WP	1,426,641	3,899	$	26.22		102,232	$	28.01		109,211
MH-107800-MP	290,486	806	$	31.50		25,389	$	33.65		27,122
Metal Halide Contemporary										
MH-12000-con	36,536	528	$	9.29		4,905	$	9.92		5,238
MH-12000-con-MP	121,818	1,764	$	17.13		30,217	$	18.30		32,281
MH-32000-con	306,662	2,035	$	12.90		26,252	$	13.78		28,042
MH-32000-con-MP	665,690	4,424	$	20.73		91,710	$	22.14		97,947
MH-107800-con	314,967	869	$	26.04		22,629	$	27.82		24,176
MH-107800-con-MP	694,079	1,925	$	33.88		65,219	$	36.19		69,666
Sub-Total	62,811,814	805,034			$	6,294,099			$	6,724,596
Partial Month billings						49,671				53,069
Total Calculated at Base Rates					$	6,343,770			$	6,777,664
Correction Factor						1.000377				1.000377
Total Afler Application of Correction Factor					$	6,341,376			$	6,775,107
Fuel Clause Billings - proforma for rollin						48,198				48,198
Merger Surcredit						(149,592)				(149,592)
Value Delivery Surcredit						(18,946)				(18,946)
VDT Amortization & Surcredit Adjustment						802				802
Adjustment to Reflect Year-End Customers						71,430				76,316
Total Rate P.O. Lt.					$	6,293,269			$	6,731,885
Proposed Increase										438,616

KENTUCKY UTILITIES COMPANY
ATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	KWH	Total Lights	Present Rates	Calculated Revenue @ Present Rates	Settlement Rates	Calculated Revenue @ Proposed Rates
Customer Outdoor Lighting				(see Exhibit 9)		
Inc-2500 (move to St. Lt) (1)	9,660	144	$ 5.12	$ 737	$ 7.61	$ 1,096
MV-3500 (move to St. Lt) (1)	20,097	478	$ 6.25	2,988	$ 7.61	3,638
MV-7000 (move to St. Lt.) (1)	8,411,057	120.910	$ 7.14	863,297	$ 7.61	920,125
Special Lighting	950,602	6,274	$ 6.16	38.648	$ 6.58	41,283
Speclai Lighting	359,447	2,218	$ 8.21	18,210	$ 8.77	19,452
Subtotal	9,750,863	130,024		$ 923.880		$ 985,593
Partial month billings				5,701		6,082
Total Calculated at Base Rates				$ 929,581		$ 991,675
Correction Factor				1.000087		1.000087
Total After Application of Correction Factor				$ 929,500		$ 991,589
Fuel Clause Billings - proforma for rollin				7,246		7,246
Merger Surcredit				(21,779)		(21,779)
Value Delivery Surcredit				(2,723)		(2,723)
VDT Amortization & Surcredit Adjustment				115		115
Adjustment to Reflect Year-End Customers				(19,194)		(20,476)
Total Rate C.O. Lt.				5 893,164		5 953,970
Proposed Increase						60.807

Louisville Gas and Electric Company
Summary of Settlement Electric Rate Increase by Rate Class
For the 12 months Ended September 30,2002

	Adjusted Billings at Current Rates	Proposed Increase In Revenue As Filed	Percentage Increase	Increase Per Settlement	Percentage increase	Percentage of Total
Residential	$ 220,310,529	$ 26,430,885	12.00%	$ 18,708,395	8.49%	43.148%
General Service	83,504,883	8,978,115	10.75%	6,483,208	7.76%	14.952%
Large Commercial Rate LC	132,177,625	13,708,637	10.37%	10,242,386	7.75%	23.622%
Industrial Power Rate LP	100,837,138	10,100,134	10.02%	5,625,092	5.58%	12.973%
Special Contracts	28,070,944	3,028,038	10.79%	1,422,016	5.07%	3.280%
Street Lighting	11,678,144	1,386,185	11.87%	877,787	7.52%	2.024%
TOTAL ULTIMATE CONSUMERS	$ 576,579,264	$ 63,631,994	11.04%	$ 43,358,883	7.52%	100.00%
Increase in Miscellaneous Charges	848,569	133,331		45,302		
TOTAL INCREASE IN REVENUE	$ 577,427,833	$ 63	11.04%	$ 43,404,185	7.52%	

LOUISVILLE GAS AND ELECTRIC COMPANY
SUMMARY OF SETTLEMENT ELECTRIC RATE INCREASE BY RATE CLASS
BASED ON ADJUSTED SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
REVISED TO INCLUDE JANUARY 2004 ECR BASE RATES ROLLIN

Rate Class	Calculated Test Period Billings as Modified to Reflect Janaury 2004 ECR Rollin Rates	Settlement Increase in Revenue	Percentage Increase
Residential Rate R	$ 219,577,320		
Residential Water Heating	733,209.04		
Total Residential	220,310,529	$ 18,708,395	8.49%
General Service Rate GS	83,495,405		
Commercial Water Heating	9,479		
Total General Service	83,504,883	6,483,208	7.76%
Large Commercial Rate LC			
Primary	6,577,911		
Secondary	100,311,410		
Primary	10,683,797		
Secondary	14,604,508		
Total Rate LCTOD	132,177,625	10,242,386	7.75%
Industrial Power Rate LP			
Primary	4,567,163		
Secondary	25,929,168		
Transmission	11,530,567		
Primary	56,811,559		
Secondary	1,998,682		
Total Rate LPTOD	100,837,138	5,625,092	5.58%
Special Contracts			
Special Contracts	6,890,944		
Special Contracts			
Special Contracts	4,895,550		
Special Contracts	6,624,286		
Special Contracts	7,845,834		
Special Contracts	1,814,330		
Total Special Contracts	28,070,944	1,422,016	5.07%
Public Street Lighting Rate PSL	4,910,190		
Street Lighting Energy Rate SLE	142,487		
Outdoor Lighting Rate OL	6,066,969		
Traffic Lighting Rate TLE	558,499		
	11,678,144	877,787	7.52%
Total Ultimate Consumers	$ 576,579,264	$ 43,358,883	7.52%
Increase in Miscellaneous Charges	$ 715,238	$ 45,302	6.33%
Total Increase In Revenue	$ 577,294,502	$ 43,404,185	7.52%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
EASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
RESIDENTIAL RATE R						
Customer Charges	4,037,207		$ 3.40	$ 13,726,504	$ 5.00	$ 20,166,035
Energy Charges		kWh's				
First 600 kWh - Summer Season		704,635,241	$ 0.06149	43,328,021	$ 0.05867	41,481,877
Over 600 kWh - Summer Season		876,768,392	$ 0.06319	55,402,995	$ 0.05867	51,615,355
First 600 kWh - Winter Season		1,267,566,536	$ 0.05669	72,992,260	$ 0.05867	75,799,160
Over 600 kWh -Winter Season		973,572,745	$ 0.04370	42,545,129	$ 0.05687	57,314,227
Total Energy				214,268,405		226,210,619
Total Rate R @ base rates		3,842,544,916		$ 227,994,909		$ 246,396,654
RESIDENTIAL PREPAID METERING RPP						
Facilities Charges	5,462		$ 2.05	$ 11.197	$ 2.05	$ 11,197
Customer Charges	5,462		$ 3.40	16.571	$ 5.00	27.310
		kWh's				
Energy Charges		5,164,866	$ 0.05661	293,416	$ 0.05667	304,056
Total Prepaid Metering RPP @ base rates				$ 323.184		$ 342,563
Subtotal @ base rates before application of correction factor				$ 228,318,093		$ 246,739,217
Correction Factor -			1.002361		1.002361	
Subtotal @ base rates after application of Correction factor		3,847,709,782		$ 227,780,293		$ 246,158,026
Fuel Adjustment Clause. proforma for rollin				(1,499,234)		(1,499,234)
Merger Surcredit				(6,469,016)		(6,469,016)
Value Delivery Surcredit				(1,464,356)		(1,484,358)
VDT Amortization & Surcredit Adjustment				17,356		17,356
Adjustment to Reflect Year-End Customers		21,505,743		1,232,279		1,336,006
TOTAL RESIDENTIAL RATES R 8 RPP				I 219,577,320		I 238,058,781
PROPOSED INCREASE						$ 18,481,461
Percentage Increase						6.42%

LG&E Electric Exhibit 1
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LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
WATER HEATING RATE WH						
Residential Water **Heating**						
Customer Charges	73.228		$ 0.97	$ 71,031	$ -	$
Energy Charges		*kWh's*				
Summer **Season**		4,808,217	$ 0.04132	198.678	$ 0.05887	283.060
Winter Season		12,388,791	$ 0.04132	511.905	$ 0.05887	729.328
		17,197,008				
Total Residential Water Heating @ base rates		17,197,008		$ 781.612		$ 1,012,388
Commercial Water Heating						
Customer Charges	1.501		$ 0.97	$ 1,456	$ -	$
Energy Charges		*kWh's*				
Summer Season		67.741	$ 0.04132	2,799	$ 0.07086	4.800
Winter Season		141.564	$ 0.04132	5.849	$ 0.06313	8.937
		209,305				
Total Commercial Water Heating @ base rates		209,305		$ 10.104		$ 13,737
Subtotal @ base rates before **application** of correction factor				I 791,716		**$ 1,026,125**
Correction Factor -			1.003426		1.003426	
Subtotal @ base rates **after** application of correction factor		17,408,313		I 789,012		I **1,022,621**
Fuel Adjustment Clause - proforma for **rollin**				(10.373)		(10,373)
Merger Surcredit				(21.169)		(21.169)
Value Delivery Surcredit				(4,846)		(4,846)
VDT Amortization & Surcredit Adjustment				57		57
Adjustment to Reflect Year-End Customers		(229,190)		(9,993)		(13,095)
TOTAL WATER HEATING RATE WH				■ 742.688		I 973,185
PROPOSED INCREASE						**$ 230,507**
Percentage Increase						**31.04%**

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
GENERAL SERVICE RATE GS						
Customer Charges - Sungle Phase	329,431		$ 4.02	$ 1,324,313	$ 10.00	$ 3,294,310
Customer Charges - Three Phase	156,788		$ 8.05	1,262,143	$ 15.00	2,351,820
Energy Charges		*kWh's*				
Summer Season		505,580,412	$ 0.06865	34,708,095	$ 0.0708	35,825,428
Winter Season		799,975,176	$ 0.06092	48,734,488	$ 0.0633	50,502,433
Total Energy				83,442,583		86,327,861
Primary Service Discounts				(27,354)		(29,245)
Total Rate GS @ base rates		1,305,555,588		$ 86,001,685		$ 91,944,746
SPACE HEATING RIDER TO RATE GS						
Customer Charges	9,221		$ 2.33	$ 21,485	$	$ -
Energy Charges		*kWh's*				
Summer Season			$ -	-	$ 0.07086	-
Winter Season		29,731,262	$ 0.04372	1,299,851	$ 0.06313	1,876,935
Total Space Heating Rider @ base rates		29,731,262		$ 1,321,336		$ 1,876,935
Subtotal @ base rates before application of correction factor				**$ 87,323,020**		**$ 93,821,681**
Correction Factor -			0.999589		0.999589	
Subtotal @ base rates after application of correction factor		1,335,286,850		**$ 87,358,902**		**$ 93,860,233**
Fuel Adjustment Clause - proforma for rollin				(621,080)		(621,080)
Merger Surcredit				(2,417,927)		(2,417,927)
Value Delivery Surcredit				(551,407)		(551,407)
VDT Amortization & Surcredit Adjustment				6,447		6,447
Adjustment to Reflect Year-End Customers		(4,415,970)		(279,531)		(301,226)
TOTAL GENERAL SERVICE RATE GS & SH RIDER				**$ 83,495,405**		**$ 89,975,041**
PROPOSED INCREASE						**$ 6,479,636**
Percentage Increase						7.76%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
LARGE COMMERCIAL RATE LC - PRIMARY VOLTAGE						
Customer Charges	531		$ 17.70	5 9,399	$ 65.00	5 34,515
Demand Charges		*kW-Months*				
Summer Season		127,056	$ 8.44	1,072,353	$ 12.32	1,565,330
Winter Season		214.932	$ 5.64	1,212,216	$ 9.52	2,046,153
		341.968				
		kWh's				
Energy Charges		154,967,220	5 0.02959	4,565,480	$ 0.02349	3,640,180
Subtotal @ base rates before application of correction factor				I 6,879,448		I 7286.178
Correction Factor -			0.999428		0.999426	
Subtotal @ base rates after application of correction factor				I 6,883,383		I 7290,346
Fuel Adjustment Clause - proforma for rollin				(72,627)		(72,627)
Merger Surcredit				(190,189)		(190,189)
Value Delivery Surcredit				(43.162)		(43.162)
VDT Amortization & Surcredit Adjustment				505		505
Adjustment to Reflect Year-End Customers		#REF!				
TOTAL LARGE COMMERCIAL RATE LC PRIMARY				$ 6,577,911		I 6,984,873
PROPOSED INCREASE						$ 406.962
Percentage Increase						6.19%

LG&E Electric Exhibit 1

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
LARGE COMMERCIAL RATE LC .SECONDARY VOLTAGE						
Customer Charges	30,959		$ 17.70	$ 547,974	5 65.00	5 2,012,335
Demand Charges		kW-Months				
Summer Season		1,823,049	$ 10.32	18,813,866	$ 14.20	25,887,296
Winter Season		3,242,275	$ 7.26	23,538,917	5 11.14	36.1 18,944
		5,065,324				
Energy Charges		kWh's 2,059,176,673	$ 0.02959	60,931,038	5 0.02349	48,370,060
Subtotal @ base rates before application of correction factoı				$ 103,831,794		$ 112,388,634
Correction Factor -			0.999428		0.999428	
Subtotal @ base rates after application of correction factor				$ 103,891,193		$ 112,452,929
Fuel Adjustment Clause. pmforma for rollin				(1,002,645)		(1,002,645)
Merger Surcredit				(2,866,140)		(2,866,140)
Value Delivery Surcredit				(651,470)		(651,470)
VDT Amortization 6 Surcredit Adjustment				7,617		7,617
Adjustment to Reflect Year-End Customers		19,155,120		932.854		1,013,228
TOTAL LARGE COMMERCIAL RATE LC SECONDARY				$ 100,311,410		$ 108,953,519
PROPOSED INCREASE						$ 8,642,109
Percentage Increase						8.62%
Total Large Commercial Rate LC				$ 106,889,321		$ 115,938,392
PROPOSED INCREASE						$ 9,049,072
Percentage Increase						8.47%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roil-In Rater	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rater
LARGE COMMERCIAL RATE LCTOD - PRIMARY VOLTAGE					
Customer Charges	123	$ 19.76	$ 2,433	$ 90.00	$ 11,070
	kW-Months				
Basic Demand Charges	520,367	$ 1.98	1,030,327	$ 2.17	1,129,196
Peak Demand Charges	*kW-Months*				
Summer Peak	194,877	$ 6.63	1,292,035	$ 10.15	1,978,002
Winter Peak	322.246	$ 3.54	1,140,756	$ 7.35	2,368,523
	517,125				
	kWh's				
Energy Charges	261,433,800	$ 0.02963	7,746,263	$ 0.02349	6,141,060
Subtotal @ base rates before application of correction factor			$ 11,211,636		$ 11,627,871
Correction Factor -		1.002249		1.002249	
Subtotal @ base rates after application of correction factor			I 11,166,675		$ 11,601,776
Fuel Adjustment Clause - proforma for rollin			(125,669)		(125.669)
Merger Surcredit			(306,135)		(306.135)
Value Delivery Surcredit			(69,688)		(69,688)
VDT Amortization 8 Surcredit Adjustment			615		815
Adjustment to Reflect Year-End Customers					
TOTAL LARGE COMMERCIAL RATE LCTOD PRIMARY			$ 10,663,797		I 11,098,899
PROPOSED INCREASE					$ 415,102
Percentage Increase					3.89%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
LARGE COMMERCIAL RATE LCTOD .SECONDARY VOLTAGE						
Customer Charges	604		$ 19.76	$ 11,947	$ 90.00	$ 54,360
		kW-Months				
Basic Demand Charges		671.385	$ 3.68	2,470,697	$ 3.22	2,161,860
Peak Demand Charges		kW-Months				
Summer Peak		232,987	$ 6.63	1,544,704	$ 10.98	2,558,197
Winter Peak		433,763	$ 3.54	1,535,521	$ 7.92	3,435,403
		666,750				
		kWh's				
Energy Charges		308,993,871	$ 0.02963	9,155,488	$ 0.02349	7,258,266
Subtotal @ base rates before application of correction factor				$ 14,718,357		$ 15,468,086
Correction Factor -			1.002249		1.002249	
Subtotal @ base rates after application of correction factor				$ 14,685,327		$ 15,433,373
Fuel Adjustment Clause. proforma for rollin				(153,023)		(153,023)
Merger Surcredit				(403,395)		(403,395)
Value Delivery Surcredit				(91.549)		(91,549)
VDT Amortization & Surcredit Adjustment				1.070		1,070
Adjustment to Reflect Year-End Customers		12,359,754		568.077		596,243
TOTAL LARGE COMMERCIAL RATE LCTOD SECONDARY				$ 14,604,508		$ 15,382,720
PROPOSED INCREASE						$ 778.212
Percentage Increase						5.33%
TOTAL LARGE COMMERCIAL RATE LCTOO				$ 25,288,305		$ 26,481,619
PROPOSEDINCREASE						$ 1,193,314
Percentage Increase						4.72%
TOTAL LARGE COMMERCIAL (LC and LC-TOD)				$ 132,177,625		$ 142,420,011
PROPOSEDINCREASE						$ 10,242,388
Percentage Increase						7.75%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LP - TRANSMISSION VOLTAGE					
Customer Charges		5 43.78	$	$ 90.00	5
Demand Charges	*kW-Months*				
Summer Season		$ 7.59		$ 11.35	
Winter Season		$ 5.00		$ 8.76	
	kWh's				
Energy Charger		$ 0.02542		$ 0.02000	
Power Factor Provision	*kW-Months*				
Summer Season		5 7.59		$ 11.35	
Winter Season		$ 5.00		$ 8.76	
Subtotal @ base rates before application of correction factor			$ -		$
Correction Factor.					
Subtotal @ base rates after application of correction factor			$		$
Fuel Adjustment Clause. proforma for rollin					
Merger Surcredit					
Value Delivery Surcredit					
VDT Amortization & Surcredit Adjustment					
Adjustment to Reflect Year-End Customers					
TOTAL INDUSTRIAL POWER RATE LP PRIMARY					$ -
PROPOSED INCREASE					$ -
Percentage Increase					

Note: Currently no customers are served under this rate

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LP - PRIMARY VOLTAGE					
Customer Charges	494	$ 43.78	$ 21,627	$ 90.00	$ 44,460
Demand Charger	*kW-Months*				
Summer Season	95,177	$ 8.78	835,654	$ 12.55	1,194,471
winter Season	181,277	$ 6.17	1,118,479	$ 9.96	1,805,519
	276,454				
	kWh's				
Energy Charges	111,622,714	$ 0.02542	2,837,449	$ 0.02000	2,232,454
Power Factor Provision	*kW-Months*				
Summer Season	(806)	$ 8.78	(7,077)	$ 12.55	(10,115)
Winter Season	(3,501)	$ 6.17	(21,601)	$ 9.96	(34.870)
	(4,307)				
Subtotal @ base rates before application of correction factor			$ 4,784,532		$ 5,231,919
Correction Factor -		0.999681		0.999681	
Subtotal @ base rates after application of correction factor			$ 4,706,080		$ 5,233,590
Fuel Adjustment Clause - proforma for rollin			(58.665)		(58.665)
Merger Surcredit			(130,757)		(130,757)
Value Delivery Surcredit			(29,824)		(29,824)
VDT Amortization & Surcredit Adjustment			349		349
Adjustment to Reflect Year-End Customers					
TOTAL INDUSTRIAL POWER RATE LP PRIMARY			$ 4,567,163		$ 5,014,693
PROPOSED INCREASE					$ 447,530
Percentage Increase					9.80%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LP -SECONDARY VOLTAGE						
Customer Charges	4,225		$ 43.76	$ 184,971	5 90.00	$ 380.250
Demand Charges		*kW-Months*				
Summer Season		485.652	$ 10.69	5,300,656	$ 14.35	7.115.476
Winter Season		927,407	$ 8.11	7,521,271	$ 11.76	10,906,306
		1,423,259				
		kWh's				
Energy Charges		553,636,275	$ 0.02542	14,078,518	$ 0.02000	11,076,726
Power Factor Provision		*kW-Months*				
Summer Season		(4,581)	$ 10.69	(48,971)	$ 14.35	(65,737)
Winter Season		(10,121)	$ 6.11	(82,061)	$ 11.76	(119,023)
		(14,702)				
Subtotal @ base rates before application of correction factor				$ 26,954,365		I 29,293,998
Correction Factor -			0.999661		0.999681	
Subtotal @ base rates after application of correction factor				$ 26,962,971		$ 29,303,351
Fuel Adjustment Clause - proforma for rollin				1277.626)		(277.626)
Merger Surcredit				(738,856)		(736.656)
Value Delivery Surcredit				(167.175)		(167,175)
M T Amortization & Surcredit Adjustment				1,965		1,955
Adjustment to Reflect Year-End Customers		3,146,798		147.900		161,327
TOTAL INDUSTRIAL POWER RATE LP SECONDARY				$ 25,929,168		$ 28,282,975
PROPOSED INCREASE						I 2,353,807
Percentage increase						9.08%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON ES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT :S REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN API TO TEST PERIOD LING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LPTOD - TRANSMISSION VOLTAGE					
Customer Charges	73	$ 45.81	$ 3.344	$ 120.00	$ 8.760
	kW-Months				
Basic Demand Charges	696.768	$ 2.10	1,463,255	$ 2.33	1,623,516
Peak Demand Charges	*kW-Months*				
Summer Peak	234.813	$ 5.50	1,291,472	$ 9.02	2,116,013
Winter Peak	454,878	$ 2.92	1,328,244	$ 6.43	2,924,866
	689,691				
	kWh's				
Energy Charges	376,359,726	$ 0.02542	9,567,064	$ 0.02000	7,527,195
Power Factor Provision	*kW-Months*				
Basic Demand	(25.159)	$ 2.10	(52,834)	$ 2.33	(58.620)
Summer Peak	(7,762)	$ 5.50	(42,691)	$ 9.02	(70.013)
Winter Peak	([illegible]215)	$ 2.92	(50.268)	$ 6.43	(110,692)
	kW-Months				
Interruptible Service Rider	411,322	$ (3.30)	(1,357,363)	5 (3.10)	(1,275,098)
Subtotal @ base rates before application of correction factor			$ 12,150,223		$. 12,687,925
Correction Factor -		1.000343		1.000343	
Subtotal @ base rates after application of correction factor			I 12,146,053		$ 12,083,570
Fuel Adjustment Clause - proforma for rollin			(213,291)		(213,291)
Merger Surcredit			(328.889)		(328.889)
Value Delivery Surcredit			(74,173)		(74.173)
VDT Amortization & Surcredit Adjustment			867		867
Adjustment lo Reflect Year-End Customers					
TOTAL INDUSTRIAL POWER RATE LPTOD TRANSMISSION			$ 11,530,567		$ 12,068,084
PROPOSED INCREASE					$ 537,517
percentage Increase					4.66%
TOTAL INDUSTRIAL POWER RATE LPTOD TRANSMISSION (without Interruptible Credit)			I 12,887,929		$ 13,343,182
PROPOSED INCREASE (without **Interruptible Credit)**					$ 455.253
percentage increase					3.53%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LPTOD - PRIMARY VOLTAGE					
Customer Charges	540	$ 45.61	$ 24.737	$ 120.00	$ 64,800
	kW-Months				
Basic Demand Charges	2,963,564	$ 3.29	9,750,126	$ 3.52	10,431,745
Peak Demand Charges	*kW-Months*				
Summer Peak	996.472	$ 5.50	5,480,596	$ 9.03	8,998,142
Winter Peak	1,952,825	$ 2.92	5,702,249	$ 6.44	12,576,193
	2,949,297				
	kWh's				
Energy Charges	1,597,360,760	$ 0.02542	40,604,91 1	$ 0.02000	31,947,215
Power Factor Provision	*kW-Months*				
Basic Demand	(103,903)	$ 3.29	(341,840)	$ 3.52	(365,737)
Summer Peak	(41,348)	$ 5.50	(227.4121	$ 9.03	(373,369)
Winter Peak	(58,2311	$ 2.92	(170,035)	$ 6.44	(375.008)
	kW-Months				
Interruptible Service Rider	344.897	$ (3.30)	(1,138,160)	$ (3.20)	(1,103,670)
Subtotal @ bare rates before application of correction factoı			$ 59,685,172		I 61,800,311
Correction Factor -		1.000342		1.000342	
Subtotal @ base rates after application of correction factor			$ 59,664,762		$ 61,779,178
Fuel Adjustment Clause - proforma for rollin			(864,770)		(864,770)
Merger Surcredit			(1,626,347)		(1,626,347)
Value Delivery Surcredit			(366.371)		(366,371)
VOT Amortization 8 Surcredit Adjustment			4.284		4.284
Adjustment to Reflect Year-End Customers					
TOTAL INDUSTRIAL POWER RATE LPTOD PRIMARY			I 56.81 1,559		I 58,925,974
PROPOSED INCREASE					$ 2,444,446
Percentage Increase					3.72%
TOTAL INDUSTRIAL POWER RATE LPTOD PRIMARY (without Interruptible Credit)			$ 57,949,719		$ 60,029,644
PROPOSED INCREASE (without Interruptible Credit)					$ 2,079,926
Percentage Increase					3.59%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates		Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
INDUSTRIAL POWER RATE LPTOD - SECONDARY VOLTAGE								
Customer Charges	151		$ 45.81	$	6,917	$ 120.00	$	18,120
		kW-Months						
Basic Demand Charges		114,966	$ 5.25		603.572	$ 4.62		531.143
Peak Demand Charges		*kW-Months*						
Summer Peak		31.727	$ 5.50		174,499	$ 9.73		308.704
Winter Peak		80,068	$ 2.92		233,799	$ 7.14		571.666
		111.795						
		kWh's						
Energy Charges		42,810,915	$ 0.02542		1,088253	$ 0.02000		856,218
Power Factor Provision		*kW-Months*						
Basic Demand		(1,951)	$ 5.25		(10.243)	$ 4.82		(9,014)
Summer Peak		(533)	$ 5.50		(2,932)	$ 9.73		(5,186)
Winter Peak		(1.404)	$ 2.92		(4.100)	$ 7.14		(10.025)
Subtotal @ base rates before application of correction factor				$	2,089,765		I	2,281,846
Correction Factor -			1.000343			1.000343		
Subtotal @ base rates after application of correction factor				I	2,089,048		$	2,260,870
Fuel Adjustment Clause - proforma lor rollin					(21,506)			(21,506)
Merger Surcredit					(56.520)			(56.520)
Value Delivery Surcredit					(12.486)			(12,486)
VOT Amortization & Surcredit Adjustment					146			146
Adjustment to Reflect Year-End Customers								
TOTAL INDUSTRIAL POWER RATE LPTOD SECONDARY				$	1,998,882		$	2,170,504
PROPOSED INCREASE							I	171,822
Percentage Increase								8.80%
TOTAL INDUSTRIAL POWER RATE LESS INTERRUPTIBLE CREDIT				$	103,332,661		I	108,840,999
PROPOSED INCREASE							$	5,508,337
Percentage Increase								5.33%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED *TO* TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
SPECIAL CONTRACT					
Demand Charger	*kW-Months*				
Summer Season	154.000	$ 6.43	1,298,220	$ 11.94	1,838,760
winter Season	216.450	$ 6.24	1,350,648	5 9.75	2,110,388
	370.450				
	kWh's				
Energy Charges	195,880,000	$ 0.02437	4,773,596	$ 0.02000	3,917,600
Power Factor Provision	*kW-Months*				
Summer Season	(11.539)	$ 8.43	(97.275)	$ 11.94	(137.778)
Winter Season	(16,4501	$ 6.24	(102.649)	$ 9.75	(160,389)
	(27.969)				
Subtotal @ base rates before application of correction factor			$ 7,222,539		$ 7,568,580
Correction Factor -		1.000000		1.000000	
Subtotal @ base rates after application of correction factor			$ 7,222,538		$ 7,568,580
Fuel Adjustment Clause. proforma for rollin			(66.299)		(86.299)
Merger Surcredit			(199.899)		(199,899)
Value Delivery Surcredit			(45,934)		(45.934)
VDT Amortization & Surcredit Adjustment			537		537
TOTAL SPECIAL CONTRACT			I 6,890,944		I 7,236,985
PROPOSED INCREASE					$ 346,041
Percentage Increase					5.02%

LG&E Electric Exhibit 1
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LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SAI ES FOR THE 12 MONTHS ENDED ; EPTEMBEF 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
SPECIAL CONTRACT									
	kW-Months								
Demand Charges	221.864	$	11.01		2,442,723	$	11.15		2,473,784
	kWh's								
Energy Charges	145,699,200	$	0.01852		2,898,349	$	0.02000		2,913,984
Subtotal @ base rater before application of correction factor				I	5,141,072			$	5,387,768
Correction Factor-			1.000000				1.000000		
Subtotal @ base rates after application of correction factor				I	5,141,072			$	5,387,788
Fuel Adjustment Clause. proforma for rollin					(75.153)				(75.153)
Merger Surcredit					(139,387)				(139,387)
Value Delivery Surcredit					(31,349)				(31,349)
VDT Amortization 8 Surcredit Adjustment					367				367
TOTAL SPECIAL CONTRACT				$	4,895,550			$	5,142,246
PROPOSED INCREASE								$	248.896
Percentage Increase									5.04%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
SPECIAL CONTRACT					
Customer Charger	12	$ 74.29	$ 891	5 120.00	$ 1,440
	kW-Months				
Basic Demand Charges	402,555	$ 5.93	2,387,151	$ 6.30	2,536,097
Peak Demand Charges	kW-Months				
Summer Peak	137,065	$ 8.19	1,122,562	$ 7.65	1,048,547
Winter Peak	238,810	$ 3.81	909.866	$ 3.27	780.909
	375,875				
	kWh's				
Energy Charges	155,404,800	5 0.01751	2,721,138	$ 0.02000	3,108,096
Power Factor Provision	kW-Months				
Basic Demand	(16.663)	$ 5.93	(110.671)	5 6.30	(117,576)
Summer Peak	(6,720)	$ 8.19	(55.036)	5 7.65	(51.407)
Winter Peak	(10,724)	5 3.61	(40.860)	5 3.27	(35,068)
	kW-Months				
interruptible Service Rider		$		$ (3.30)	
Subtotal @ base rates before application of correction factor			$ 6,935,043		$ 7271.037
Correction Factor -		1.000000		1.000000	
Subtotal @ base rates after application of correction factor			$ 6,935,043		$ 7,271,037
Fuel Adjustment Clause. proforma for rollin			(76.751)		(76.751)
Merger Surcredit			(191,055)		(191.055)
Value Delivery Surcredit			(43.460)		(43.460)
VDT Amortization & Surcredit Adjustment			508		508
TOTAL SPECIAL CONTRACT			$ 6,624,286		$ 6,960,280
PROPOSED INCREASE					$ 335.994
Percentage Increase					5.07%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
SPECIAL CONTRACT					
Customer Charger	12	$ 74.29	$ 891	$ 74.29	$ 891
	kW-Months				
Basic Demand Charges	624,000	$ 4.36	2,720,640	$ 4.62	2,882,880
Peak Demand **Charges**	*kW-Months*				
Summer **Peak**	180,000	$ 8.19	1,474,200	$ 7.65	1,377,000
Winter Peak	360,000	$ 3.81	1,371,600	$ 3.27	1,177,200
	540,000				
	kWh's				
Energy Charges	199,644,549	$ 0.01751	3,495,776	$ 0.02000	3,992,891
P a e r Factor Provision	*kW-Months*				
Basic Demand	(49,504)	$ 4.36	(215,837)	$ 4.62	(228.708)
Summer Peak	(14,040)	$ 8.19	(114.988)	$ 7.65	(107.408)
Winter Peak	(28,800)	$ 3.81	(109,7281	5 3.27	(94,176)
	kW-Months				
Interruptible Service Rider	120.000	$ (3.30)	(396,000)	$ (3.10)	(372.000)
Station House Credit			(1,200)		(1,200)
Subtotal @ base rates before application of correction factor			$ 8,225,354		$ 8,627,312
Correction Factor.		1.000078		1.000078	
Subtotal @ base rates after application **of** correction factor			$ 8,224,717		$ 8,626,703
Fuel Adjustment Clause - **proforma** for rollin			(102,665)		(102,665)
Merger Surcredit			(225,529)		(225.529)
Value Delivery Surcredit			(51.289)		(51,289)
VDT **Amortization &** Surcredit **Adjustment**			600		600
TOTAL SPECIAL CONTRACT			$ 7,845,834		$ 8,247,820
PROPOSED INCREASE					$ 401,986
Percentage increase					5.12%
TOTAL SPECIAL CONTRACT (without Interruptible Credit)			8 241 034		$ 8,619,820
PROPOSED INCREASE					$ 377,986
Percentage increase					4.59%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
SPECIAL CONTRACT					
	kW-Months				
Demand Charges	104,943	5 7.53	790.221	$ 8.33	874,175
	kWh's				
Energy Charges	56.404.800	5 0.01975	1,115,772	$ 0.01088	1,123,117
Subtotal @ base rates before application of correction factor			$ 1,905,993		$ 1,997,292
Correction Factor -		1.000000		1.000000	
Subtotal @ base rates after application of correction factor			$ 1,905,993		$ 1,997,292
Fuel Adjustment Clause. proforma for rollin			(28.377)		(28,377)
Merger Surcredit			(51.718)		(51.718)
Value Delivery Surcredit			(11,705)		(11.705)
VDT Amortization 6 Surcredit Adjustment			137		137
TOTAL SPECIAL CONTRACT			$ 1,814,330		$ 1,905,829
PROPOSED INCREASE					$ 91,299
Percentage Increase					5.03%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
STREET LIGHTING ENERGY RATE SLE		kWh's				
Energy Charges		3,992,315	$ 0.03788	151,229	$ 0.04059	162,048
Subtotal @ base rates before application of correction factor				$ 151,229		$ 162,048
Correction Factor -			1.001986		1.001986	
Subtotal @ base rates after application of correction factor				$ 150,929		$ 161,727
Fuel Adjustment Clause - proforma for rollin				(2,325)		(2,325)
Merger Surcredit				(4,081)		(4,081)
Value Delivery Surcredit				(887)		(887)
VDT Amortization & Surcredit Adjustment				10		10
Adjustment to Reflect Year-End Customers		(31,939)		(1,159)		(1,247)
TOTAL STREET LIGHTING ENERGY RATE SLE				$ 142,487		$ 153,197
PROPOSED INCREASE						$ 10,711
Percentage Increase						7.52%
TRAFFIC LIGHTING ENERGY RATE TLE						
Customer Charges	10,370		$2.54	$ 26,340	$ 2.80	$ 29,036
		kWh's				
Energy Charges		11,472,338	$ 0.04777	548,034	$ 0.05114	586,695
Subtotal @ base rates before application of correction factor				$ 574,373		$ 615,731
Correction Factor -			0.993299		0.993299	
Subtotal @ base rates after application of correction factor				$ 578,248		$ 619,885
Fuel Adjustment Clause - proforma for rollin				(6,274)		(6,274)
Merger Surcredit				(15,832)		(15,832)
Value Delivery Surcredit				(3,492)		(3,492)
VDT Amortization & Surcredit Adjustment				41		41
Adjustment to Reflect Year-End Customers		119,502		5,808		6,245
TOTAL TRAFFIC LIGHTING ENERGY RATE TLE				$ 558,499		$ 600,573
PROPOSED INCREASE						$ 42,075
Percentage Increase						7.53%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roil-In Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
PUBLIC STREET LIGHTING RATE PSL					
	Lights				
OVERHEAD SERVICE					
Mercury Vapor - Installed prior to January 1, 1991					
100 Wall	564	$6.08	$ 3,429	$ 6.52	$ 3.677
175 Wall	35.831	$7.08	253,083	$ 7.59	271.957
250 Wall	58.512	$8.03	469,851	$ 8.81	503.788
400 **Wall**	85.032	$9.56	812.906	$ 10.25	871.578
400 Walt (metal pole)		$13.90		$ 14.90	
1000 Wan	168	$17.64	2.964	$ 18.92	3.179
Mercury Vapor - Installed after December 31. 1990					
100 wan					
175 Wall	24	$ 8.81	211	$ 9.45	227
250 Wall	631	$ 9.86	6.222	$ 10.57	8,670
400 Wall	204	$ 11.60	2,407	$ 12.85	2.581
400 Wall (metal pole)					
1000 Wan	96	$ 21.24	2.039	$ 22.78	2.187
Sodium Vapor - Installed prior to January 1.1991					
100 wan	216	$7.27	1,570	$ 7.80	1.885
150 Watt	23,400	$8.89	203,346	$ 9.32	218,088
250 **Walt**	26.448	$10.37	274,268	$ 11.12	294.102
400 Wall	54,105	$10.72	580,008	$ 11.49	621.666
1000 wan					
Sodium Vapor - Installed after December 31,1990					
100 **Watt**	4,290	$ 7.27	31,188	$ 7.80	33,462
150 Wall	6.347	$ 6.69	55.155	$ 9.32	59,154
250 Wall	840	$ 10.37	8,711	$ 11.12	9,341
400 wan	22.793	$ 10.72	244.341	$ 11.49	261,892
1000 **Watt**	24	$ 24.37	585	$ 28.13	627

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Roll-In Rates	Calculated Revenue at Present Rater	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
PUBLIC STREET LIGHTING RATE PSL (continued)					
	Lights				
UNDERGROUND SERVICE					
Mercury Vapor- Installed prior to January 1, 1991					
100 Watt Top Mounted	1,200	$ 9.98	11.952	$ 10.68	12,816
175 Watt Top Mounted	12.888	$ 10.86	139.984	$ 11.65	150.145
175 Watt	1,236	$ 14.77	18.256	$ 15.84	19,578
250 Wan	12,120	$ 15.78	191,011	$ 16.90	204.828
400 Wan	8.364	$ 18.49	154,650	$ 19.83	165.858
400 Wan (metal pole)	4.452	5 18.49	82.317	$ 19.83	88.283
Mercury Vapor - Installed after December 31. 1990					
100 Wan Top Mounted		$ 12.30		5 13.19	
175 Watt Top Mounted	444	$ 13.32	5.914	$ 14.28	6,340
175 Watt		5 21.04		$ 22.56	
250 Watt	300	$ 22.08	8.624	$ 23.68	7.104
400 Wall		$ 24.02		$ 25.76	
400 Watt (metal pole)		$ 24.02		$ 25.76	
Sodium Vapor - Installed prior to January 1, 1991					
70 Walt Top Mounted				$	
100 Watt Top Mounted	23.244	5 10.94	254.289	$ 11.73	272.652
150 Watt Top Mounted				$	
150 wan	2,340	5 18.96	44,366	$ 20.33	47.572
250 Wall	6,744	$ 20.06	135,285	$ 21.51	145,063
250 Wall (metal pale)	1.344	$ 20.06	26,981	5 21.51	28,909
400 Watt	7.404	$ 21.42	158.594	$ 22.97	170,070
400 Wan (metal pole)	2.160	5 21.42	46.267	$ 22.97	49.615
1000 Watt					
Sodium Vapor. installed after December 31, 1990					
70 Watt Top Mounted	2,316	$ 10.55	24.434	$ 11.31	26,194
100 Watt Top Mounted	58.564	$ 10.94	640,690	$ 11.73	688,956
150 Watt Top Mounted	4.124	$ 16.18	66.726	$ 17.35	71,551
150 watt	1.125	$ 18.96	21,330	$ 20.33	22,871
250 Watt	444	$ 20.06	8,907	$ 21.51	9,550
250 Watt (metal pale)		5 20.06		$ 21.51	
400 Watt	2,936	$ 21.42	62,889	$ 22.97	67.440
400 Wan (metal pole)	12	$ 21.42	257	5 22.97	276
1000 Watt	24	$ 49.85	1,196	$ 53.45	1,283

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants	Jan. 2004 ECR Rail-in Rates	Calculated Revenue at Present Rates	Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
PUBLIC STREET UGHTING RATE PSL (continued)					
DECORATIVE UGHTING FIXTURES					
installed after December 31, 1990	*Lights*				
Acorn w/decorative baskets					
70 Watt Sodium Vapor	132	$ 14.57	1.923	5 15.62	2,062
100 Watt Sodium Vapor	1,044	$ 15.15	15.817	$ 16.25	16,965
8-Sided Coach					
70 Watt Sodium Vapor	432	I 14.76	6,316	$ 15.83	6.839
100 Watt Sodium Vapor		5 15.33		I 16.44	
Poles	*Poles*				
10ft Smooth	569	5 8.73	4.970	$ 9.36	5,328
10ft Fluted	702	$ 10.42	7.312	$ 11.17	7.838
Bases	*Bases*				
Old Town/Manchester	115	$ 2.80	322	$ 3.00	345
Cheaspeak/Franklin	233	5 3.00	700	$ 3.22	751
Jefferson/Winchester	710	5 3.03	2.151	5 3.25	2.307
Norfolk/Essex	142	$ 3.19	453	I 3.42	486
Subtotal @ base rates before application of Correction factor			$ 5,095,104		$ 5,463,137
Correction Factor -		0.997825		0.997825	
Subtotal @ base rates after application of correction factor			$ 5,106,893		$ 5,415,640
Fuel Adjustment Clause - proforma for rollin			(28.056)		(28.056)
Merger Surcredit			(140.918)		(140.918)
Value Delivery Surcredit			(31.091)		(31,091)
VDT Amortization & Surcredit Adjustment			364		364
Adjustment to Reflect Year-End Customers	24		2,999		3,225
TOTAL PUBLIC STREET LIGHTING RATE PSL			$ 4,910,190		$ 5,279,170
PROPOSED INCREASE					$ 368,901
Percentage increase					7.51%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC PATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rates
OUTDOOR LIGHTING SERVICE RATE OL									
	Lights								
OVERHEAD SERVICE									
Mercury Vapor - Installed prior to January 1, 1991									
100 Wall	728	$	6.78	$	4,936	$	7.27	$	5.293
175 Wan	39.923	$	7.63		304,612	$	8.18		326,570
250 Wall	19.562	$	8.63		168,820	$	9.25		180,949
400 Wall	21.141	$	10.44		220.712	$	11.19		236,568
1000 Watt	4,443	$	18.93		84.106	$	20.30		90,193
Sodium Vapor. Installed prior To January 1, 1991									
100 wan	2,836	$	7.53		21,355	$	8.07		22.887
150 wan	7,820	$	9.82		75,228	$	10.32		80,702
250 Watt	4.927	$	11.32		55,774	$	12.14		59,814
400 Wan	50.448	$	11.89		599,627	$	12.75		643.212
1000 Watt									
	Poles								
Pole Charges	56.430	$	1.66		93.674	$	1.78		100,445
	Lights								
UNDERGROUND SERVICE									
Mercury Vapor. Installed prior Io January 1, 1991									
100 Wall Top Mounted	516	$	11.84		6,109	$	12.70		6,553
175 Watt Top Mounted	6,781	$	12.57		85,237	$	13.48		91,408
Sodium Vapor. Installed prior to January 1, 1991									
70 Wall Top Mounted		$	10.55			$	11.31		
100 Watt Top Mounted	15.235	$	13.93		212.224	$	14.94		227,611
150 Watt Top Mounted									
150 Wan		$	18.98			$	20.35		
250 Watt	384	$	21.72		8,340	$	23.29		8.943
400 Watt	509	$	23.85		12,140	$	25.57		13.015
1000 Wall									

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003
PRESENT RATES REVISED TO INCLUDE JANUARY 2004 ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-in Rates	Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin	Calculated Revenue at Settlement Rates
OUTDOOR LIGHTING SERVICE RATE OL (continued)							
OVERHEAD SERVICE							
Mercury Vapor- Installed after December 31. 1990							
100 watt							
175 Watt	1.127	5	8.99	10,132	$	9.64	10.664
250 Watt	733	$	10.04	7,359	5	10.77	7,894
400 Walt	2,232	$	11.98	28,739	5	12.85	28,681
1000 watt	4,756	$	21.50	102,254	$	23.05	109,626
Sodium Vapor - Installed **after December** 31. 1990							
100 watt	23,025	5	7.53	173.378	5	8.07	185,612
150 wan	19,460	$	9.62	187.205	5	10.32	200.827
250 Watt	4,986	$	11.32	55.442	$	12.14	60,530
400 Wall	107.923	$	11.89	1,283,204	$	12.75	1,376,018
1000 watt	154	5	28.16	4,337	$	30.20	4,651
	Poles						
Pole Charges	46.247	$	1.66	76,770	$	1.78	62,320
UNDERGROUND SERVICE							
Mercury Vapor. Installed after December 31.1990							
100 Wan Top **Mounted**		$	12.57		$	13.48	
175 Wall **Top Mounted**	2.600	$	13.51	35.126	5	14.49	37,874
Sodium Vapor. Installed after December 31. 1990							
70 Watt Top **Mounted**	14,991	5	10.55	158.155	$	11.31	189.546
100 Watt **Top Mounted**	95.063	$	13.93	1,324,228	$	14.94	1,420,241
150 Walt **Top Mounted**	9.267	$	18.89	156,520	$	18.11	167,825
150 Watt	5.145	$	18.98	97.652	$	20.35	104,701
250 wan	5.605	$	21.72	121,741	5	23.29	130,540
400 Watt	16,237	$	23.85	387.252	$	25.57	415.180
1000 watt	286	5	53.63	15.338	$	57.51	16,448

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003
PRESENT **RATES** REVISED TO INCLUDE JANUARY **2004** ECR ROLLIN APPLIED TO TEST PERIOD BILLING DETERMINANTS

	Billing Determinants		Jan. 2004 ECR Roll-In Rates		Calculated Revenue at Present Rates		Settlement Rates with ECR Rollin		Calculated Revenue at Settlement Rater
OUTDOOR LIGHTING SERVICE RATE OL (continued)									
DECORATIVE LIGHTING FIXTURES									
Installed after December 31.1990	*Lights*								
Acorn w/decorative baskets									
70 Walt Sodium Vapor	243	$	14.95		3.633	I	16.03		3,895
100 Watt Sodium Vapor	1.668	$	15.64		26.088	$	16.77		27,972
8-Sided Coach									
70 Watt Sodium Vapor	869	$	15.12		13.442	I	16.21		14.411
100 Watt Sodium Vapor	336	$	15.61		5.312	$	16.95		5,695
Poles	*Poles*								
10ft Smooth	1.392	$	6.73		12.152	$	9.36		13,029
10ft Fluted	1.716	I	10.42		17.880	$	11.17		19,167
Bases	*Bases*								
Old Town/Manchester	297	I	2.80		832	$	3.00		892
Cheaspeak/Franklin	603	$	3.00		1,809	$	3.22		1,942
Jefferson/Winchester	1,836	I	3.03		5,562	$	3.25		5,968
Norfolk/Essex	367	I	3.19		1,171	$	3.42		1,256
Subtotal @ bass rates before application of correction factor				$	6,264,808			$	6,717,769
Correction Factor.			0.996100				0.996100		
Subtotal @ bass **rates** after application **of** correction factor				$	8,289,337			$	6,744,072
Fuel Adjustment Clause - proforma for rollin					(29,131)				(29,131)
Merger Surcredit					(172,037)				(172,037)
Value Delivery Surcredit					(38,766)				(38,766)
VDT Amortization & Surcredit Adjustment					453				453
Adjustment to Reflect Year-End **Customers**	115				17.114				18,401
TOTAL OUTDOOR LIGHTING RATE OL				$	6,066,969			$	6,522,990
PROPOSED INCREASE								$	456,021
Percentage Increase									7.52%

Louisville Gas and Electric Company
Summary of Settlement Gas Rate increase by Rate Class
Based on Adjusted Sales and Transportation
For the 12 months Ended September 30, 2003

	Adjusted Billings at Current Rates	Proposed increase In Revenue As Filed	Percentage Increase	increase Per Proposed Settlement	Percentage increase	Percentage of Total
Residential Gas Service Rate RGS	$ 226,193,722	$ 17,187,887	7.60%	$ 9,782,051	4.32%	83.01%
Firm Commercial Gas Service Rate CGS	103,596,812	1,593,870	1.54%	1,774,266	1.71%	15.06%
Firm Industrial Gas Service Rate IGS	11,973,655	198.751	1.66%	218,727	1.83%	1.86%
As Available Gas Service Rate AAGS	3,005,383	6	0.00%	8.553	0.28%	0.07%
Firm Transportation Service Rate FT	3,939,208		0.00%		0.00%	0.00%
Pooling Service Rate PS-FT	60,600		0.00%		0.00%	0.00%
Special Contracts	1,681,970		0.00%		0.00%	0.00%
Off-System Sales	-	-		-		
Total Sales and Transportation	350,451,351	18,980,514	5.42%	11,783,597	3.36%	100.00%
Forfeited Discounts	1,264,157					
Reconnection Charges	49,349	12,006		4,002		
Meter Test Charge		31,464		31,464		
Thlrd Trlp inspection Charges	3,105	80.730		80.730		
Other Miscellaneous Revenues	591,441					
Total Revenue	$ 352,359,402	$ 19,104,714	5.42%	$ 11,899,793	3.38%	

LG&E Gas Exhibit 1
Page 1 of 9

LOUISVILLE GAS AND ELECTRIC COMPANY
SUMMARY OF SETTLEMENT GAS RATE INCREASE BY RATE *CLASS*
BASED ON ADJUSTED SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

REVENUE	(1) Booked Revenue Adjusted to As Billed Basis	(2) Elimination of Gas Supply Cost Recovery (GSC) Revenues (See Exhibit 7)	(3) Elimination of Demand-Side Management (DSM) Revenues	(4) Temperature Normalization Adjustment (See Exhibit 8)	(5) Year-End Customers Adjustment (See Exhibit 9)	(6) Adjustment to Reflect Rate Switching and Plant Closings (See Exhibit 10)	(7) VDT Amortization & Surcredit Adjustment	(8) GSC @ Current Nov03-Jan04 Charges	(9) Adjusted Billings at Current Rates	(10) Proposed Increase in Revenue	(11) Percentage Increase
Residential Gas Service Rate RGS	$ 189,080,204	$ (133,698,514)	$ (1,034,237)	$ 19,079	$ 114,237	$	149,202	$ 171,563,752	$ 226,193,722	$ 9,782,051	4.32%
Firm Commercial Gas Service Rate CGS	86,731,073	(65,436,260)	(455,264)	66,427	(113,425)	8,662	68,362	82,727,197	103,596,812	1,774,266	1.71%
Firm Industrial Gas Service Rate IGS	9,878,763	(7,988,579)	-	(36,404)	18,710		7,518	10,093,647	11,973,655	218,727	1.83%
As Available Gas Service Rate AAGS	3,079,249	(2,757,374)	(4,883)	(3,938)	(986)	(63,851)	2,451	2,754,718	3,005,383	8,553	0.28%
Firm Transportation Service Rate FT	5,308,129	(1,499,335)	(21,375)	(30,424)	(75,115)	13,838	2,953	242,537	3,939,208	-	0.00%
Pooling Service Rate PS-FT	60,600								60,600	-	0.00%
Special Contracts	1,708,443			(27,762)	-		1,290		1,681,970	-	0.00%
Off-System Sales	10,242,833	(10,242,833)									
Total Sales and Transportation	$ 306,087,293	$ (221,622,896)	$ (1,515,759)	$ (13,022)	$ (56,581)	$ (41,331)	$ 231,796	$ 267,381,851	$ 350,451,351	$ 11,783,597	3.36%
Forfeited Discounts	1,264,157								1,264,157		
Reconnection Charges	49,349								49,349	4,002	
Meter Test Charge	-								-	31,464	
Third Trip Inspection Charges	3,105								3,105	80,730	
Other Miscellaneous Revenues	591,441								591,441		
Total Revenue	$ 307,995,344								$ 352,359,402	$ 11,899,793	3.38%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Residential Gas Service Rate RGS	*Customer Months*	*Per customer*		*Per Customer*	
Customer Charges:	3,332,464	$7.00	23,327,246	$8.50	28,325,944
	MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component:	24,301,485.5	$1,3457	32,702,509	$1.5470	37,594,390
			56,029,757		65,920,342
Residential Gas Service Rate RGS Summer A/C Rider					
	MCF	*Per Mcf*		*Per Mcf*	
Distribution Coot Component:	94.0	$0.8457	79	$1.5470	145
Subtotal	24,301,579.5		$ 56,029,837		$ 65,920,487
Correction Factor		0.99938		0.99936	
Subtotal Rate RGS after Application of Correction Factor	24,301,579.5		$ 56,065,875		$ 65,962,888
Value Delivery Surcredit			(795,671)		(795,671)
VDT Amortization 8 Surcredit Adjustment			149,202		149,202
Temperature Normalization Adjustment	(671,526.1)	$1.3457	(903,673)	$1.5470	(1,038,851)
Adjustment to Reflect Year-End Customers	48,936.3		114,237		134,453
GSC at Current (Nov03-Jan04) Charges. GSCC	23,678,989.7	$ 7,2454	171,563,752	$ 7.2454	$ 171,563,752
Total Residential Gas Service Rate RGS	23,678,989.7		$ 226,193,723		$ 235,975,773
Proposed Increase in Revenue					$9,782,051
					4.32%

LG&E Gas Exhibit 1
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LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30,2003

	Billing Determinants		Present Rates	Calculated Revenue at Present Rates		Settlement Rates	Calculated RY at Proposed Rates
Flrm Commercial Gas Service Rate CGS	Customer Months		Per Customer			Per Customer	
Customer Charges (Meters < 5000 cf/hr)	281,590		$16.50	4,646,235		$16.50	4,646,235
Customer Charges (Meters >= 5000 cf/hr)	11,489		$117.00	1,344,213		$117.00	1,344,213
	293,079						
	MCF		Per Mcf			Per Mcf	
Distribution Cost Component:							
On Peak Mcf	10,842,797.2		$1.3457	14,591,152		$1.4968	16,229,499
Off Peak Mcf	877,844.1		$0.8457	742,393		$0 9968	876.035
	11,720,641.3			21,323,993			23,094,962
Gas Transportation Service/Standby Rider to Rate CGS	Customer Months		Per customer			Per Customer	
Administrative Charges:	24		$90.00	2,160		$90.00	2,160
	MCF		Pet Mcf			Per Mcf	
Distribution Cost Component:							
On Peak M d	88,084.0		$1.3457	118.535		$1,4968	131,644
Off Peak Mcf	17,767.4		$0.8457	15,026		$0.9968	17,711
	105,851.I			135,721			151,715
Firm Commercial Gas Service Rate CGS Summer A/C Rider	MCF		Per Mcf			Per Mcf	
Distribution Cast Component:	40,2540		$0.8457	34,043		$1.4966	60.252
Subtotal	11,866,746.7		1	21,493,156		$	23,306,949
Correction Factor			0.99129			0.99129	
Subtotal Rate CGS after Application of Correction Factor	11,866,746.7			$21,682,647			123.511,114
Value Delivery Surcredit				(364,672)			(364.672)
VDT Amortization & Surcredit Adjustment				68.382			88.382
Temperature Normalization Adjustment	(306,160.2)		$1,3457	(412.0001		$1.4966	(456,261)
Adjustment to Reflect Year-End Customers	(81,647.3)			(113,4251			(122,932)
Adjustment for Rate Switching & Plant Closings: Customer Chgs.	12		$117.00	1,404		$117.00	1.404
Distribution Chgs. -On-Peak	4,407.5		$1.3457	5,931		$1.4968	8,597
Distribution Chgs. - Off-Peak	1,592.0		$0.6457	1,346		$0.9968	1,567
GSC at Current (Nov03-Jan04) Charges - GSCC	11,402,368.1	$	7.2454	82,614,718			82,614,718
GSC at Current Charges - Pipeline Supplier Demand Component	102,570.6	1	1.0966	112,479			112,479
Total Commercial Gar Service Rate CGS	11,504,938.7			$103,596,811			$105,311,071
Proposed Increase in Revenue							$1,774,266
							1.71%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30.2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Firm Industrial Gas Service Rate IGS	*Customer Months*	*Per Customer*		*Per Customer*	
Customer Charges (Meters < 5000 cf/hr)	1,463	$16.50	24,140	$16.50	24,140
Customer Charges (Meters >= 5000 cf/hr)	1,245	$1 17.00	145,665	$117.00	145.665
	MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component:					
On Peak Mcf	1,002,298.3	$1.3457	1,346,793	$1.4966	1,500,240
Off Peak M d	401,064.1	$0.6457	339,160	$0.9966	399,761
	1,403,362.4		1,657,777		2,069,825
Gas Transportation Service/Standby Rider lo Rate IGS	*Customer Months*	*Per Customer*		*Per Customer*	
Administrative Charges:	25	$90.00	2,250	$90.00	2.250
	MCF	*Per Mcf*		*Per Mcf*	
Distribution *Cod* Componenl:					
On Peak Mcf	7,600.3	$1,3457	10,226	$1.4966	11.376
Off Peak Mcf	11,340.7	$0.8457	9,591	$0.9966	11,304
	16,9410		22.069		24.931
Subtotal	1,422,303.4		$ 1,879,846		$ 2,094,756
Correction Factor		0.97367		0.97367	
Subtotal Rate IGS after Application of Correction Factor	1,422,303.4		$ 1,930,275		$ 2,150,950
Value Delivery Surcredit			(40,091)		(40,091)
VDT Amortization & Surcredit Adjustment			7,516		7.516
Rate Switching / Plant Closings Adjustment					
Customer Chgs		$117.00		$117.00	
On Peak *Md*		$1.3457		$1.4968	
Off Peak M d		$0.8457		$0.9968	
Temperature Normalization Adjustment	(27,0520)	$1.3457	(36,404)	$1.4966	(40,491)
Adjustment lo Reflect Year-End Customers	13.764		16.710		20,650
GSC at Current (Nov03-Jan04) Charges - GSCC	1,390,271.1	$ 7 2454	10,073,070		10,073,070
GSC at Current Charges - Pipeline Supplier Demand Component	18,764.3	$ 1.0966	20,577		20.577
Total Industrial Gas Service Rate IGS	1,409,035.4		$ 11,973,655		$ 12,192,382
Proposed Increase In Revenue					$218.727
					1.83%

LOUISVILLE GAS AND 31813313 COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

		Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
As Available Gas Service Rate AAGS						
Customers Currently Taking						
Service Under Rate G-6 and G-6/TS		*Customer Months*	*Per Customer*		*Per Customer*	
Customer Charges:	G-6	181	$150.00	27,150	$150.00	27,150
Administrative Charges:	G-6/TS	36	$90.00	3,240	$90.00	3,240
		217		30,390		30,390
		MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component:						
	G-6	212,614.6	$0.6855	145,747	$0.5252	111,665
	G-6/TS	58,991.2	$0.6855	40,438	$0.5252	30,982
Subtotal		271,605.8		216,576		173,037
Customers Currently Taking						
Service Under Rate G-7	*Minimum Bills*	*Customer Months*	*Per Minimum*		*Per Customer*	
Minimum Bills	13	144	$500.00	6,500	$150.00	21,600
		MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component		249,255.8	$0.4300	107,180	$0.5252	130,909
Subtotal		249,255.8		113,680		152,509
Subtotal Rate AAGS		520,861 6		$ **330,256**		$ **325,547**
Correction Factor			1.000583		1.000583	
Total Rate AAGS after Application of Correction Factor		520,861.6		$ **330,063**		$ **325,357**
Value Delivery Surcredit - G6				(6,580)		(6,580)
VDT Amortization & Surcredit Adjustment - G6				1,234		1,234
Value Delivery Surcredit - G7				(6,492)		(6,492)
VDT Amortization & Surcredit Adjustment - G7				1,217		1,217
Temperature Normalization Adjustment - G6		(2,467.9)	$0.6855	(1,692)	$0.5252	(1,296)
Temperature Normalization Adjustment - G7		(5,226.3)	$0.4300	(2,247)	$0.5252	(2,745)
Adjustment to Reflect Year-End Customers - G6		(1,240.3)		(988)		(790)
Adjustment to Reflect Year-End Customers - G7		-				
Adjustment for G6 Rate Switching & Plant Closings:	Customer Chgs.	(36)	0150.00	(5,400)	$150.00	(5,400)
	Administrative Chgs.	(24)	$90.00	(2,160)	69000	(2,160)
	Distribution Chgs.	(82,116.8)	$0.6855	(56,291)	$0.5252	(43,128)
GSC at Current (Nov03-Jan04) Charges - GSCC		371,355.1	$ 7.2454	2,690,616		2690616
GSC at Current Charges - Pipeline Supplier Demand Component		58,455.2	$ 1.0966	64,102		64,102
Total As Available Gas Service Rate AAGS		429,810.2		$ **3,005,383**		$ **3,013,936**
Proposed Increase in Revenue						**$8,553**
						0.28%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Firm Transportation Service (Non-Standby) Rate FT					
	Customer Months	*Per Customer*		*Per Customer*	
Administrative Charges:	894	$90.00	80,460	$90.00	80,460
	MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component	8,392,666.4	$0.4300	3,608,847	$0.4300	3,608,847
Utilization Charge for Daily Imbalances (UCDI):					
Daily Storage Charge:	*930,330.8*	$0.1200	111,640		111,640
Subtotal Rate FT	8,392,666.4		$ **3,800,946**		$ **3,800,946**
Correction Factor		0.99994			
Total Rate FT after Application of Correction Factor	8,392,666.4		$ **3,801,164**	*	**3,801,164**
Value Delivery Surcredit			(15,746)		(15,746)
VDT Amortization & Surcredit Adjustment			2,953		2,953
Adjustment for G6 Rate Switching & Plant Closings: Administrative Chgs.	12	$90.00	1,080		1,080
Distribution Chgs.	29,670.5	$0.4300	12,758		12,758
Temperature Normalization Adjustment	(70,753.1)	$0.4300	(30,424)		(30,424)
Adjustment to Reflect Year-End Customers	(167,555.0)		(75,115)		(75,115)
UCDI Charge - Daily Demand Charge (current Nov03-Jan04)	930,330.8	$ 0.2607	242,537		242,537
Total Firm Transportation (Non-Standby) Rate FT	8,154,358.3		$ **3,939,208**		$ **3,939,208**
Proposed Increase in Revenue					$ **-**
					0.00%
Pooling Service Rate PS-FT	*Customer Months*	*Per Customer*			
Pooling Charges:	808	$75.00	$60,600		$60,600
Correction Factor		1.00000			
Total Pooling Service Rate PS-FT			**$60,600**		**$60,600**
Proposed Increase in Revenue					**$0**
					0.00%

LOUISVILLE GAS AND ELECTRIC COMPANY
[illegible]ION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Special Contract	*Customer Months*	*Per Customer*		*Per Customer*	
Customer Charges:	12	$180.00	2,160	$180.00	2,160
Administrative Charges:	12	$90.00	1,080	$90.00	1,080
	MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component	1,107,542.5	$0.1049	116,181	$0.1049	116,181
Demand Charges	112,956.9	$2.7500	310,631	$2.7500	310,631
Subtotal		$	430,053	$	430,053
Correction Factor		0.99994		0.99994	
Subtotal After Application of Correction Factor			430,078		430,078
VDT Amortization & Surcredit Adjustment			329		329
Value Delivery Surcredit			(1,754)		(1,754)
Temperature Normalization Adjustment	(36,490.3)	$0.1049	(3,828)	$0.1049	(3,828)
Total Special Contract	1,071,052.2	$	424,825	$	424,825
Proposed Increase in Revenue				$	-
					0.00%
Special Contract	*Customer Months*	*Per Customer*		*Per Customer*	
Customer Charges:	12	$180.00	2,160	$180.00	2,160
Administrative Charges:	12	$90.00	1,080	$90.00	1,080
	MCF	*Per Mcf*		*Per Mcf*	
Distribution Cost Component	1,324,790.6	$0.1049	138,971	$0.1049	138,971
Demand Charges	71,028.5	$2.7500	195,328	$2.7500	195,328
Subtotal		$	337,539	$	337,539
Correction Factor		1.00000		1.00000	
Subtotal After Application of Correction Factor		$	337,539	$	337,539
VDT Amortization & Surcredit Adjustment			263		263
Value Delivery Surcredit			(1,402)		(1,402)
Temperature Adjustment	(10,561.7)	$0.1049	(1,108)	$0.1049	(1,108)
Total Special Contract	1,314,228.9	$	335,292	$	335,292
Proposed Increase in Revenue				$	-
					0.00%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF SETTLEMENT GAS RATE INCREASE
BASED ON SALES AND TRANSPORTATION
FOR THE 12 MONTHS ENDED SEPTEMBER 30

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
Special Contract	*Customer Months*	*Per Customer*		*Per Customer*	
Customer Charges:	24	$180.00	4.320	$180.00	4.320
Administrative Charges:	24	$90.00	2.160	$90.00	2,160
	MCF	Per *M d*		*Per Mcf*	
Distribution Cost Component	2,941,326.6	$0 3200	941.225	$0.3200	041.225
Subtotal		I	947.705	$	947.705
Correction Factor		*1.00000*		1.00000	
Subtotal After Application of Correction Factor		$	947.704	I	947,704
VDT Amortization & Surcredit Adjustment			698		698
Value Delivery Surcredit			(3,723)		(3,723)
Temperature Adjustment	(71,333.1)	$0.3200	(22,827)	$0.3200	(22,627)
Total Special Contract	2,869,993.5	$	921,853	$	921.853
Proposed Increase in Revenue				I	
					0.00%

Reserved Balancing Service Rate RBS

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Settlement Rates	Calculated Revenue at Proposed Rates
	MCF	*Per Mcf*		*Per Mcf*	
Monthly Balancing Charge:		$ 3.65	$0	I 3.85	$0
Monthly Demand Charge:		I 7.93	$0	I 7.93	$0
			$0		$0
Correction Factor				0	
Total after Application of Correction Factor			$0		$0
Proposed Increase in Revenue					$0
					0.00%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

MAY 0 4 2004

PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	))))	CASE NO: 2003-00433

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO: 2003-00434

STIPULATION

WHEREAS, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Companies") filed applications to make general adjustments to the Companies' rates, terms and conditions on December 29, 2003 in Case Nos. 2003-00433 and 2003-00434;

WHEREAS, The Kroger Co. was granted full intervention by the Kentucky Public Service Commission ("Commission") on January 22, 2004;

WHEREAS, the Companies and The Kroger Co. (the "parties") wish to facilitate the disposition of these two proceedings through the submission of a joint stipulation on revenue requirement and rate design issues; and,

NOW THEREFORE, pursuant to 807 KAR 5:001 Section 4(6) the parties stipulate as follows:

The Companies will request authority from the Commission to offer experimental time-ofday rate schedules for commercial customers whose maximum monthly demands were greater than 250 KW and less than 2,000 KW during the calendar year 2003 on a revenue-neutral basis. The experimental time-ofday rate schedules will be available to 100 accounts currently served under Rate LC by LG&E, and to 100 accounts currently served under Rate LP by KU.

2 After three years, the Companies will evaluate the performance of the experimental time-of-day rate schedules for the following purposes: (i) to determine the amount of load shifted from the on-peak period to the off-peak period, (ii) to determine the amount of revenue loss from the experimental time-of-day rate schedules, (iii) to evaluate customer acceptance of the experimental time-ofday rate schedules, and (iv) to evaluate the potential for implementing the experimental time-of-day rate schedules as either a permanent demand-side management program or as a standard rate schedule. The Companies shall file a report with the Commission describing their findings within six months after the first three years of implementation of the experimental time-of-day rate schedules. The experimental time-ofday rate schedules shall remain in effect until the rate schedules are terminated by order of the commission.

3. Any customer-specific costs of offering the experimental time-ofday rate schedules, including but not limited to the additional cost of the metering equipment, meter reading, and customer-specific billing costs, shall be recovered through a monthly facilities charge billed to the participants of the experimental time-of-day rate schedules. The monthly facilities charge shall be $15.00 per customer per month.

4. The experimental time-ofday rate schedule for customers served under LG&E's Rate LC shall include energy charges corresponding to $0.0300 per kWh during the designated

on-peak period and $0.0140 per kWh during the designated off-peak period. These charges are based on an energy charge filed by LG&E of $0.0240/kWh. Should the Commission approve an energy charge in this proceeding for Rate LC that differs from the one filed by LG&E, the on-peak and off-peak energy charges shall be adjusted pro-rata to reflect the energy charge established by the Commission. During the summer billing months of June through September, the designated on-peak period shall be: weekdays, from 10 AM. to 9 P.M. Eastern Standard Time (EST) during the four monthly billing periods of June through September. During the winter billing months of October through May, the designated on-peak period shall be: weekdays, from 8 A.M. to 10 P.M Eastern Standard Time (EST) during the eight monthly billing periods of October through May. The designated off-peak period shall be all hours not included during the summer and winter peak periods. The demand and customer charges shall be the Same as approved by the Commission for Rate. LC.

5. The experimental time-of-day rate schedule for customers served under KU's Schedule LP shall include energy charges corresponding to $0.0280 per kWh during the designated on-peak period and $0.0150 per kWh during the designated off-peak period. These charges are based on an energy charge filed by KU of $0.0220/kWh. Should the Commission approve an energy charge for Schedule LP in this proceeding that differs from the one filed by KU, the on-peak and off-peak energy charges shall be adjusted pro-rata to reflect the energy charge established by the Commission. During the summer billing months of June through September, the designated on-peak period shall be: weekdays, from 10 A.M. to 9 P.M. Eastern Standard Time (EST) during the four monthly billing periods of June through September. During the winter billing months of October through May, the designated on-peak period shall be: weekdays, from 8 A.M. to 10 P M Eastern Standard Time (EST) during the eight monthly

billing periods of October through May. The designated off-peak period shall be all hours not included during the summer and winter peak periods. The demand and customer charges shall be the same as approved by the Commission for Schedule LP.

6. The non-customer specific costs of modifying LG&E's customer billing system to bill customers under the experimental time-of-day rate schedule will be recovered through a charge per kWh billed to customers taking service under Rate LC determined in the same manner as the DSM Cost Recovery Component of LG&E's Demand-Side Management Cost Recovery Mechanism. The cost of modifying LG&E's customer billing system is estimated to be a total of $87,150, or $29,050 annually for three years. The charge would be $0.00001/kWh.

7. The non-customer specific costs of modifying KU's customer billing system to bill customers under the experimental time-of-day rate schedule will be recovered through a charge per kWh billed to customers taking service under Rate LP determined in the same manner as the DSM Cost Recovery Component of KU's Demand-Side Management Cost Recovery Mechanism. The cost of modifying KU's customer billing system is estimated to be a total of $87,150, or $29,050 annually for three years. The charge would be $0.00001/kWh.

8. LG&E will collect any revenue from lost sales from the experimental time-of-day rate schedule through a charge billed to customers taking service under Rate LC determined in the same manner as the DSM Revenue From Lost Sales Component of LG&E's Demand-Side Management Cost Recovery Mechanism. The Revenue From Lost Sales will be determined annually by comparing billings of customers taking service under the experimental time-of-day rate schedule to billings computed under Rate LC for twelve–month periods.

9. KU will collect any revenue from lost sales from the experimental time-of-day rate schedule through a charge billed to customers taking service under Rate LP determined in

the same manner as the DSM Revenue From Lost Sales Component of KU's Demand-Side Management Cost Recovery Mechanism. The Revenue From Lost Sales will be determined annually by comparing billings of customers taking service under the experimental time-of-day rate schedule to billings computed under Rate LP for twelve-month periods.

10. The experimental time-of-day rate schedules will become effective fourteen weeks after the dates of the Commission's Orders in the above-captioned proceedings.

11. The Kroger Co. shall withdraw the direct testimony submitted by Kevin C. Higgins on behalf of The Kroger Co. in Case Nos. 2003-00433 and 2003-00434 and shall not otherwise contest the Companies' proposals in Case Nos. 2003-00433 and 2003-00434 regarding the application of the Merger Surcredits, the shareholder components of the Merger Surcredits, the VDT Surcredits, the shareholder components of the VDT Surcredits, the Companies' proposed revenue increase, or the Companies' proposed allocation of the rate increase.

The parties submit the foregoing stipulation is a fair, just and reasonable resolution of the issues identified herein and request the Commission to determine the resolution of the issues herein based upon the stipulation.

Dated: May 4,2004

Respectfully submitted,

Kendrick R. Riggs
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500 West Jefferson Street
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COUNSEL FOR LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

- and -

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Louisville, Kentucky 40202-3352

COUNSEL FOR THE KROGER COMPANY

STANDARD RATE SCHEDULE STOD

Small Time of Day Rate

N

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to commercial customers whose average maximum monthly demands are greater than 250 KW and less than 2,000KW.

a) STOD shall be available as an optional pilot program for three years effective 14 weeks following the Final Order in PSC Case No 2003-00433 for existing customers on Rate LC, Original Sheet No 15, PSC of Kentucky Electric No 6.
b) As an optional pilot program, STOD is restricted to 100 customers. The Company will notify all eligible customers of STOD and accept applications on a first-come-first-served basis with the beginning of business 6 weeks following the Final Order in PSC Case No 2003-00433.
c) For each year or partial year of the pilot program, programming costs plus lost revenues will be recovered from customers served under Rate LC by a program cost recovery mechanism.
d) No customers will be accepted for STOD following the end of the second year of the pilot program.
e) The Company will file a report on STOD with the Commission within six months of the end of the third year of the pilot program. Such report will detail findings and recommendations.
f) STOD shall remain in effect until terminated by order of the Commission.

RATE

Customer Charge: $80.00 per month

Plus a Demand Charge:

Winter Rate applies to the eight consecutive billing months October through May

Secondary Service -	$11.14 per KW per month
Primary Service -	$ 9.52 per KW per month

Summer Rate applies to the four consecutive billing months June through September

Secondary Service -	$14.20 per KW per month
Primary Service -	$12.32 per KW per month

Plus an Energy Charge of:

On-Peak Energy -	$0.02936 per KWH
Off-Peak Energy -	$0.01370 per KWH

Where the On-Peak Energy is defined for bills rendered during a billing period as the metered consumption from:

a) 10 A.M. to 9 P.M., Eastern Standard Time, on weekdays for the four consecutive billing months of June through September or
b) 8 A.M. to 10 P.M., Eastern Standard Time, on weekdays for the eight consecutive billing months from October through May.

All other metered consumption shall be defined as Off-Peak Energy.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest average load in kilowatts recorded during any 15-minute interval in the monthly billing period: but not less than 50% of the maximum demand similarly determined for any of the four billing periods of June through September within the 11 preceding months; nor less than 25 kilowatts (10 kilowatts to any customer served under this rate schedule on March 1, 1964).

STANDARD RATE SCHEDULE STOD

Small Time of Day Rate

N

PROGRAM COST RECOVERY MECHANISM

The monthly billing amount computed under Rate LC shall be adjusted by the Program Cost Recovery Factor which shall be calculated per KWH in accordance with the following formula:

Program Cost Recovery Factor = (PC + LR) / LPKWH

Where:

a) PC is the cost of programming the billing system and will be no more than $29,050 for each of the three years of the pilot program.
b) LR is the lost revenues of the pilot program calculated by subtracting the revenues that would have been billed under Rate LC from the revenues realized by actual billings under STOD. LR will be calculated for the first program year and applied in the second program or recovery year. That procedure will repeat for each year or partial year the pilot is in effect.
c) LPKWH is the expected KWH energy sales for the LC rate in the recovery year.
d) The Company will file any change in the Program Cost Recovery Factor with supporting calculations ten days prior to application.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 70
Demand Side Management Cost Recovery Mechanism	Sheet No. 71
Environmental Cost Recovery Surcharge	Sheet No. 72
Merger Surcredit Rider	Sheet No. 73
Earnings Sharing Mechanism	Sheet No. 74
Value Delivery Surcredit Rider	Sheet No. 75
Franchise Fee Rider	Sheet No. 76
School Tax	Sheet No. 77

MINIMUM CHARGE

The bill shall in no event be less than the Customer Charge plus the Demand Charge computed upon the billing demand for the month.

LATE PAYMENT CHARGE

The bill will be rendered at the above net charges (including net minimum bills when applicable) plus an amount equivalent to 1% thereof, which amount will be deducted provided bill *is* paid within 15 days from date

EXIT AND EMERGENCY LIGHTING

Where governmental code or regulation requires a separate circuit for exit or emergency lighting, the demand and consumption of such separate circuit may be combined for billing with those of the principal light and power circuit or circuits

TERM OF CONTRACT

For a fixed term of not less than one year and for such time thereafter until terminated by either party giving 30 days written notice to the other of the desire to terminate. A customer exiting the pilot program will not be allowed to return to it until the Commission has issued a decision on the STOD program report.

STANDARD RATE SCHEDULE STOD

Small Time of Day Rate

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto N

ELECTRIC RATE SCHEDULE STOD

Small Time-of-Day Service

APPLICABLE

In all territory sewed by the Company.

AVAILABILITY OF SERVICE

Available to commercial customers whose average maximum monthly demands are greater than 250 KW and less than 2,000KW.

a) STOD shall be available as an optional pilot program for three years effective 14 weeks following the Final Order in PSC Case No 2003-00434 for existing customers on Rate LP, Original Sheet No 20, PSC No 13.
b) As an optional pilot program, STOD is restricted to 100 customers. The Company will notify all eligible customers of STOD and accept applications on a first-come-first-served basis with the beginning of business *6* weeks following the Final Order in PSC Case No 2003-00434.
c) For each year or partial year of the pilot program, programming costs plus lost revenues will be recovered from customers served under Rate LP by a program cost recovery mechanism.
d) No customers will be accepted for STOD following the end of the second year of the pilot program.
e) The Company will file a report on STOD with the Commission within six months of the end of the third year of the pilot program. Such report will detail findings and recommendations
f) STOD shall remain in effect until terminated by order of the Commission.

RATE

Customer Charge: $90.00 per month

Plus a Demand Charge:

Secondary Service -	$6.65 per KW per month
Primary Service -	$6.26 per KW per month
Transmission Service -	$5.92 per KW per month

Plus an Energy Charge of:

On-Peak Energy -	$0.02800 per KWH
Off-Peak Energy -	$0.01500 per KWH

Where the On-Peak Energy is defined for bills rendered during a billing period as the metered consumption from:

a) 10 A.M. to 9 P.M., Eastern Standard Time, on weekdays for the four consecutive billing months of June through September or
b) 8 **A.M.** to 10 P.M., Eastern Standard Time, on weekdays for the eight consecutive billing months from October through May.

All other metered consumption shall be defined as Off-Peak Energy.

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average KW demand delivered to the customer during the 15-minute period of maximum use during the month.

The company reserves the right to place a KVA meter and base the billing demand on the measured KVA. The charge will be computed based on the measured KVA times 90 percent of the applicable KW charge.

ELECTRIC RATE SCHEDULE STOD

Small Time-of-Day Service

In lieu of placing a KVA meter, the Company may adjust the measured maximum load for billing purposes when power factor is less than 90 percent in accordance with the following formula:
(BASED ON POWER FACTOR MEASURED AT TIME OF MAXIMUM LOAD).

$$\text{Adjusted Maximum KW Load for Billing Purposes} = \frac{\text{Maximum Load Measured} \times 90\%}{\text{Power Factor (in Percent)}}$$

PROGRAM COST RECOVERY MECHANISM

The monthly billing amount computed under Rate LP shall be adjusted by the Program Cost Recovery Factor which shall be calculated per KWH in accordance with the following formula:

Program Cost Recovery factor = (PC + LR) / LPKWH

Where:

a) PC is the cost of programming the billing system and will be no more than $29,050 for each of the three years of the pilot program.
b) LR is the lost revenues of the pilot program calculated by subtracting the revenues that would have been billed under Rate LP from the revenues realized by actual billings under STOD. LR will be calculated for the first program year and applied in the second program or recovery year. That procedure will repeat for each year or partial year the pilot is in effect.
c) LPKWH is the expected KWH energy sales for the LP rate in the recovery year.
d) The Company will file any changes to the Program Cost Recovery Factor with supporting calculations ten days prior to application.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 70
Demand Side Management Cost Recovery Mechanism	Sheet No. 71
Environmental Cost Recovery Surcharge	Sheet No. 72
Merger Surcredit Rider	Sheet No. 73
Earnings Sharing Mechanism	Sheet No. 74
Value Delivery Surcredit Rider	Sheet No. 75
Franchise Fee Rider	Sheet No. 76
School Tax	Sheet No. 77

MINIMUM CHARGE

Service under this schedule is subject to an annual minimum of $81.24 per kilowatt for secondary delivery, $77.16 per kilowatt for primary delivery and $73.08 per kilowatt for transmission delivery for each yearly period based on the greater of (a), (b), (c), (d), or (e) as follows:

(a) The highest monthly maximum load during such yearly period.
(b) The contract capacity, based on the expected maximum KW demand upon the system.
(c) 60 percent of the KW capacity of facilities specified by the customer.
(d) Secondary delivery, $812.40 per year; Primary delivery, $1,929.00 per year; Transmission delivery, $3,654.00 per year.
(e) Minimum may be adjusted where customer's service requires an abnormal investment in special facilities.

ELECTRIC RATE SCHEDULE STOD

Small Time-of-Day Service

Payments to be made monthly of not less than 1/12 of the Annual Minimum until the aggregate payments during the contract year equal the Annual Minimum. However, payments made in excess of the amount based on above rate schedule will be applied as a credit on billings for energy used during contract year. A new customer or an existing customer having made a permanent change in the operation of electrical equipment that materially affects the use in kilowatt-hours and/or use in kilowatts of maximum load will be given an opportunity to determine new service requirements in order to select the most favorable contract year period and rate applicable. N

DUE DATE OF BILL

Customer's payment will be due within 10 days from date of bill

TERM OF CONTRACT

For a fixed term of not less than one year and for such time thereafter until terminated by either party giving 30 days written notice to the other of the desire to terminate. A customer exiting the pilot program will not be allowed to return to it until the Commission has issued a decision on the STOD program report.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto

Case Nos. 2003-00433 and 2003-00434 – LG&E and KU
Modification of Environmental Surcharge (ECR)

KU

- The rate base, operating expenses, and gross proceeds from by-product and allowance sales included in KU's environmental surcharge associated with its 1994 Compliance Plan ("1994 Plan") will be included and recovered through KU's base rates.

- KU's 1994 Plan will be removed from its environmental surcharge.

- The Base Period Jurisdictional Environmental Surcharge Factor ("BESF) in KU's surcharge will be recalculated to remove the effects of KU's 1994 Plan. The calculation of the revised BESF will be included as part of the first monthly surcharge filing submitted after the removal of the 1994 Plan from the environmental surcharge.

- The costs and allowance expense associated with the sulfur dioxide ("SO_2") emission allowances received from the Owensboro Municipal Utilities will be included as a component of the environmental surcharge costs recovered as part of KU's Post-1994 Plan.

- For KU, any environmental surcharge reporting format that exclusively reports information associated with the 1994 Plan will be deleted from the monthly surcharge filing. For reporting formats presenting information associated with both the 1994 Plan and Post-1994 Plan, the 1994 Plan information will be shown as "0". Reporting formats will be renumbered to reflect the deleted reporting formats during the next surcharge review.

- KU's ES Form 2.31, of Emission Allowances – Current Vintage Year," will no r ce d with th no environmental surcharge s KU will continue t include Form 2.30, "Inventory of Emission All "

LG&E

- The rate base, rating expenses, and s proce d from allo sales uded i LG&E's l g associated with its 1995 Compliance Plan (' Plan") will be included and recovered t LG&E's base ates.

- l 995 Plan will be removed f m its environmental urcharge.

- The BESF in LG&E's surcharge will be recalculated t remove the effects of l 1995 Plan. The calculation f the revised BESF will be included as t f the first monthly surcharge filing submitted after the removal of the 1995 Plan from the environmental surcharge.

- For LG&E, any environmental surcharge reporting format that exclusively reports information associated with the 1995 Plan will be deleted from the monthly surcharge filing. For reporting formats presenting information associated with both the 1995 Plan and Post-1995 Plan, the 1995 Plan information will be shown as "0". Reporting formats will be renumbered to reflect the deleted reporting formats during the next surcharge review.

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00433 DATED JUNE 30, 2004

Determination of LG&E's Rate Base Allocation Ratio
And the Pro Forma Adjustments to LG&E's Electric Rate Base

Rate Base Allocation Ratio

The determination of LG&E's electric capitalization reflects the allocation of the total company capitalization using an allocation factor based on LG&E's actual test-year electric rate base compared to the total company rate base.

	Electric Rate Base As of 09/30/03	Total Company Rate Base As of 09/30/03
Total Utility Plant in Service	$3,232,386,289	$3,752,179,495
Add:		
Materials & Supplies	55,832,046	55,936,971
Gas Stored Underground	0	38,757,261
Prepayments	2,882,693	3,207,802
Cash Working Capital Allowance	52,800,999	58,441,691
Subtotal	$ 111,515,738	$ 156,343,725
Deduct:		
Accumulated Depreciation	1,339,452,661	1,522,825,598
Customer Advances	507,146	9,700,500
ADIT	326,087,270	384,571,974
SFAS 109 ADIT	(34,633,001)	(39,190,651)
Investment Tax Credit (prior law)	3,943	3,943
Subtotal	$1,631,418,019	$1,877,911,364
Net Original Cost Rate Base	$1,712,484,008	$2,030,611,856
Percentage of Electric Rate Base to Total Company Rate Base		84.33%

The electric and total company rate base calculations match those submitted by LG&E in Rives Direct Testimony, Rives Exhibit 3, page 1 of 2, except for the treatment of Accumulated Deferred Income Taxes ("ADIT"), which are described in the Order.

APPENDIX D (continued)

Pro Forma Adjustments to LG&E's Electric Rate Base

	Post-1995 Environmental Surcharge	E. W. Brown Improvement Reimburse.	SFAS No. 143 Adjustment	Carbide Lime Inventory	Commission Expense Adjustments	Total All Pro Forma Adjustments
Total Utility Plant in Service	(203,504,422)	(3,351,980)	(4,585,010)	0	0	(211,441,412)
Add:						
Materials & Supplies	0	0	0	(332,637)	0	(332,637)
Prepayments	0	0	0	0	0	0
Cash Working Capital	0	0	0	0	2,227,690	2,227,690
Subtotal	0	0	0	(332,637)	2,227,690	1,895,053
Deduct:						
Accumulated Depreciation	(1,973,149)	0	0	0	(580,797)	(2,553,946)
Customer Advances	0	0	0	0	0	0
ADIT	(596,849)	0	0	0	0	(596,849)
SFAS 109 ADIT	0	0	0	0	0	0
Investment Tax Credit	0	0	0	0	0	0
Subtotal	(2,569,998)	0	0	0	(580,797)	(3,150,795)
Net Adjustments	(200,934,424)	(3,351,980)	(4,585,010)	(332,637)	2,808,487	(206,395,564)

The adjustments for the Post-1995 Environmental Surcharge, E.W. Brown Improvement Reimbursement, and the SFAS No. 143 were provided by LG&E in its response to the Commission Staff's Third Data Request dated March 1, 2004, Item 39.

The Post-1995 Environmental Surcharge adjustment reflects the removal of all rate base-related components. The amounts shown about have been revised to include the ADIT associated with the Post-1995 Environmental Surcharge. When the corresponding adjustment is made to capitalization, the ADIT amount will not be included since ADIT is not funded by capitalization. This treatment is consistent with the Commission's decision in Case No. 1998-00426.

The Carbide Lime Inventory adjustment reflects the removal from Materials & Supplies of 2 months of this inventory from the 13-month average balance calculation. This is an adjustment proposed by the AG that the Commission agrees with.

The Commission Expense Adjustments reflect the calculation of the cash working capital allowance using the 1/8th formula and the change in Operation and Maintenance Expenses and the adjustment to depreciation expense as described in the Order.

APPENDIX E

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00433 DATED JUNE 30, 2004

Determination of LG&E's Electric Capitalization

LG&E's Electric Capitalization Prior to Adjustments

	Test Year Actual Balances	Updated Capital Structure	Revised TY Actual Balances	Rate Base Allocation Percentage	Capitalization Allocated to Electric
Long-Term Debt	797,769,753	43.32%	833,718,930	84.33%	703,075,174
Short-Term Debt	75,132,051	5.26%	101,231,800	84.33%	85,368,777
Accounts Receivable Securitization	74,800,000	0.00%	0	84.33%	0
Preferred Stock	70,424,594	3.71%	71,401,136	84.33%	60,212,578
Common Equity	906,432,535	47.71%	918,207,067	84.33%	774,324,021
Totals	1,924,558,933	100.00%	1,924,558,933		1,622,980,550

LG&E's Electric Capitalization After Adjustments

	Capitalization Allocated to Electric	Net Adjustments to Electric Capitalization	Adjusted Electric Capitalization	Adjusted Capital Structure
Long-Term Debt	703,075,174	(70,810,194)	632,264,980	42.58%
Short-Term Debt	85,368,777	(8,597,914)	76,770,863	5.17%
Preferred Stock	60,212,578	(6,064,307)	54,148,271	3.65%
Common Equity	774,324,021	(52,542,669)	721,781,352	48.60%
Totals	1,622,980,550	(138,015,084)	1,484,965,466	100.00%

APPENDIX E (continued)

Adjustments to Electric Capitalization

	Long-Term Debt	Short-Term Debt	Preferred Stock	Common Equity	Total Adjustments
Trimble County Inventories	(1,282,600)	(155,736)	(109,844)	(1,412,578)	(2,960,758)
Other Investments	(212,268)	(25,774)	(18,179)	(233,779)	(490,000)
JDIC	21,426,325	2,601,627	1,834,988	23,597,643	49,460,583
E. W. Brown Improvement	(1,452,078)	(176,314)	(124,358)	(1,599,230)	(3,351,980)
Minimum Pension Liability	0	0	0	25,443,354	25,443,354
SFAS No. 143 – ARO	(1,986,226)	(241,172)	(170,104)	(2,187,508)	(4,585,010)
Post-1995 Environmental Surcharge	(87,303,347)	(10,600,545)	(7,476,810)	(96,150,571)	(201,531,273)
Totals	(70,810,194)	(8,597,914)	(6,064,307)	(52,542,669)	(138,015,084)

The Updated Capital Structure percentages were used for adjustments allocated to all components of capitalization on a pro rata basis.
The Minimum Pension Liability impacts only the Common Equity, so a pro rata allocation to all components of capitalization is not appropriate.
As noted in Appendix C, the adjustment for the Post-1995 Environmental Surcharge does not include the balance for ADIT, since ADIT is not funded by capitalization.

APPENDIX F

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00433 DATED JUNE 30, 2004

Schedule of Adjustments

The following adjustments were proposed by LG&E in its application, accepted by the AG, and have been found reasonable and accepted by the Commission. The "+" indicates an increase while "-" indicates a decrease.

	Description	Reference Rives Exhibit 1	Change to Revenues	Change to Expenses
1.	Adjust mismatch in fuel recovery.	Sch. 1.01	-$4,406,145	-$2,005,300
2.	Adjust base rates and Fuel Adjustment Clause ("FAC") reflect a full year of FAC roll-in.	Sch. 1.02	+$547,244	0
3.	Adjustment to eliminate environmental surcharge revenues and expenses.	Sch. 1.03	-$11,228,429	-$1,766,344
4.	Eliminate electric brokered sales revenues and expenses.	Sch. 1.06	-$5,389,000	-$7,811,321
5.	Eliminate electric ESM revenues collected.	Sch. 1.07	-$6,974,780	0
6.	Eliminate ESM, environmental surcharge, and FAC in Rate Refund Account 449.	Sch. 1.08	-$7,150,231	0
7.	Eliminate demand-side management revenues and expenses.	Sch. 1.09	-$3,277,501	-$3,280,013
8.	Eliminate advertising expenses pursuant to 807 KAR 5:016.	Sch. 1.15	0	-$62,499
9.	Adjustment to remove One-Utility costs.	Sch. 1.18	0	-$1,061,924
10.	Adjustment for VDT net savings to shareholders.	Sch. 1.20	0	+$5,640,000
11.	Adjust VDT-related revenues and expenses to settlement agreement.	Sch. 1.21	+$44,485	-$224,718
12.	Adjustment for merger savings.	Sch. 1.22	-$2,758,795	+$19,427,401

APPENDIX F (continued)

	Description	Reference Rives Exhibit 1	Change to Revenues	Change to Expenses
13.	Adjustment to eliminate LG&E/KU merger amortization expense.	Sch. 1.23	0	-$2,722,005
14.	Adjustment for MISO Schedule 10 credits.	Sch. 1.24	0	+$709,577
15.	Adjust for cumulative effect of accounting change. [AG withdrew objection to adjustment; AG Post-Hearing Brief at 12]	Sch. 1.25	0	+$5,280,909
16.	Adjustment to remove E. W. Brown legal expenses.	Sch. 1.27	0	-$2,157,640
17.	Adjust for customer rate switching and customer plant closing.	Sch. 1.28	+$6,445	0
18.	Adjustment for corporate office lease expense.	Sch. 1.29	0	+$1,798,420
19.	Adjust for Cane Run repair refund.	Sch. 1.30	0	+$3,588,000
20.	Adjust for prior income tax true-ups and adjustments.	Sch. 1.38	0	-$58,593

The following adjustments were proposed in the application and later revised by LG&E, accepted by the AG, and have been found reasonable and accepted by the Commission. The "+" indicates an increase while "-" indicates a decrease.

	Description	Revision Reference	Change to Revenues	Change to Expenses
1.	Adjust base rate revenues to reflect a full year of the environmental surcharge roll-in. [Rives Ex. 1, Sch. 1.04]	PSC 3-35	+$717,788	0
2.	Adjust off-system sales revenues for the environmental surcharge calculations. [Rives Ex. 1, Sch. 1.05]	Seelye Rebuttal Ex. 2	-$2,925,817	0
3.	Adjustment to reflect amortization of ESM audit expenses. [Rives Ex. 1, Sch. 1.17]	Scott Rebuttal Ex. 5	0	+$63,933