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PUBLIC SERVICE COMMISSION

Ms. Stephanie L. Stumbo
Executive Director
Kentucky Public Service Commission
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Frankfort, Kentucky 40601

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December 19, 2008

RE: ***Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates* – Case No. 2008-00252**

***Application of Louisville Gas and Electric Company to File Depreciation Study* – Case No. 2007-00564**

Dear Ms. Stumbo:

Please find enclosed and accept for filing the original and ten (10) copies of the following testimonies in the above-referenced matters:

1. Rebuttal Tesimony of S. Bradford Rives;
2. Rebuttal Tesimony of William E. Avera;
3. Rebuttal Tesimony of Valerie L. Scott;
4. Rebuttal Tesimony of Shannon L. Charnas;
5. Rebuttal Tesimony of Lonnie E. Bellar;
6. Rebuttal Tesimony of John J. Spanos; and
7. Rebuttal Tesimony of William Steven Seelye.

Should you have any questions regarding the enclosed, please contact me at your convenience.

Sincerely,

Lonnie E. Bellar

Lonnie E. Bellar

cc: Parties of Record

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Counsel of Record

Allyson K. Sturgeon, Senior Corporate Attorney – E.ON U.S. LLC
Kendrick R. Riggs – Stoll Keenon Ogden PLLC (Louisville Gas and Electric)
W. Duncan Crosby – Stoll Keenon Ogden PLLC (Louisville Gas and Electric)
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Dennis Howard II – Office of the Attorney General (AG)
Lawerence W. Cook – Office of the Attorney General (AG)
Paul D. Adams – Office of the Attorney General (AG)
Michael L. Kurtz – Boehm, Kurtz & Lowry (KIUC)
Lisa Kilkelly – Legal Aid Society, Inc. (ACM and POWER)
David C. Brown – Stites and Harbison (Kroger)
Joe F. Childers (CAK)

Consultants to the Parties

Steve Seelye – The Prime Group (E.ON U.S. LLC)
William A. Avera – FINCAP, Inc (E.ON U.S. LLC)
John Spanos – Gannett Fleming, Inc. (E.ON U.S. LLC)
Robert Henkes (AG)
Michael Majoros – Snavely King Majoros O'Connor & Lee (AG)
Glenn Watkins – Technical Associates (AG)
Dr. J. Randall Woolridge – Smeal College of Business (AG)
Lane Kollen – Kennedy and Associates (KIUC)
Kevin C. Higgins – Energy Strategies, LLC (Kroger)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	))))	CASE NO. 2008-00252

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	CASE NO. 2007-00564

REBUTTAL TESTIMONY OF
S. BRADFORD RIVES
CHIEF FINANCIAL OFFICER
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: December 19, 2008

Q. Please state your name, position and business address.

A. My name is S. Bradford Rives. I am the Chief Financial Officer for Louisville Gas and Electric Company ("LG&E") and an employee of E.ON U.S. Services, Inc., which provides services to LG&E and Kentucky Utilities Company ("KU"). My business address is 220 West Main Street, Louisville, Kentucky.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the rebuttal testimonies of LG&E's other witnesses, and to address and respond to certain points and assertions made by intervenors to this proceeding. In particular, I will address intervenors' comments on the following topics: (1) the proposed consolidated tax adjustment; (2) the allocation of capitalization based on environmental surcharge ("ECR") rate base; (3) the effect on LG&E's capitalization of reducing the due date of bills from fifteen to ten days after the bill date; (4) the rate of return on capitalization; (5) the calculation of rate base; and (6) testimony concerning LG&E's new bank credit facilities adjustment to pro forma operating income.

<u>**General Comments**</u>

Q. Do you have any general comments you wish to make about the testimony of the intervenors?

A. Yes. Low electric rates in Kentucky exist for several reasons, including the long-term and principled method of regulation by this Commission. Over the years, the Commission has repeatedly taken a long-term view towards its policies, such as the rate treatment of construction work on progress, use of the lesser of capital structure and rate base as the method for the valuation of utility property, and calculation of taxes on a stand alone basis. Some of the adjustments proposed by the intervenors in this case stand in stark contrast to the Commission's long-standing and principled method of regulation. Acceptance of these adjustments in this case would raise serious questions about the future course of regulation and its risks to electric and gas utilities.

Summary of Other LG&E Witnesses' Rebuttal Testimonies

Q. Please summarize the rebuttal testimonies of LG&E's other witnesses.

A. I summarize the rebuttal testimonies of LG&E's other witnesses below:

- Lonnie E. Bellar
  - Mr. Bellar's testimony (1) responds to the testimony of Robert J. Henkes, witness for the Office of the Attorney General ("AG"), concerning LG&E's proposed unbilled revenues pro forma adjustment to operating income, and (2) addresses the concerns expressed in the testimony of the low-income customer advocates.
- Valerie L. Scott
  - Ms. Scott rebuts certain contentions concerning the calculation of LG&E's revenue requirements raised by Mr. Henkes, for the AG, and by Lane Kollen, for the Kentucky Industrial Utility Customers, Inc. ("KIUC") with respect to the following pro forma income adjustments: interest synchronization; MISO net expenses; Kentucky coal tax credit; recycle tax credit; labor costs; and employee benefit costs. Also, she responds to the AG's witness, Michael Majoros, concerning his recommendation for the accrued cost of removal regulatory liability to be reclassified from accumulated depreciation to Account 254 – Other Regulatory Liabilities for Regulatory Accounting, Reporting and Ratemaking Purposes.
- Shannon L. Charnas
  - Ms. Charnas rebuts testimony by Messrs. Henkes and Kollen concerning the following pro forma adjustments: annualized depreciation expense; excessive net salvage; Edison Electric Institute dues; American Gas Association dues; manufacturers' gas plant amortization expense; outside labor expenses; and miscellaneous expense adjustments.
- W. Steven Seelye
  - Mr. Seelye rebuts AG witness Glenn A. Watkins and KIUC witness Mr. Kollen concerning the electric temperature normalization adjustment. Mr. Seelye also rebuts Mr. Watkins regarding his proposed electric and gas cost of service studies, revenue allocation, and rate design. Finally, Mr. Seelye addresses cost of service and rate design issues raised by KIUC witness Stephen J. Baron.
- John Spanos

- Mr. Spanos rebuts the testimony of Messrs. Majoros, Henkes, and Kollen concerning the use of the Equal Life Group ("ELG") procedure in calculating depreciation accrual rates for all asset classes for LG&E and KU. Also, Mr. Spanos addresses the intervenors' testimony related to cost of removal.

- William E. Avera

  - Mr. Avera responds to the recommendations of AG witness Dr. J. Randall Woolridge and KIUC witness Mr. Kollen concerning the return on equity ("ROE") for LG&E's utility operations. Mr. Avera concludes that the ROE recommendations of Dr. Woolridge and Mr. Kollen fail the most fundamental test of reasonableness because they do not provide LG&E with the opportunity to earn returns that are comparable with those available from alternative investments of comparable risk.

Consolidated Tax Adjustment

Q. Do you agree with Mr. Kollen's recommendation that consolidated income tax benefits should be reflected in income tax expense?

A. Absolutely not. This recommendation, if adopted, would represent a radical and abrupt departure from almost twenty years of the Commission's well-established, sound and balanced policy prohibiting affiliate cross-subsidization.[1] The Commission should continue its long-standing practice of using the stand-alone method for income taxes.

Q. Would you please explain the course of the Commission's requirement for the stand alone method of calculating tax expenses?

A. Yes. In its May 25, 1990 Order in Case No. 89-374, *Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, the Commission approved LG&E's proposed reorganization and creation of a holding company structure. The consummation of this transaction resulted in LG&E Energy Corp.

[1] *See In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, Case No. 1989-00374, Order (May 25, 1990).

becoming the parent corporation of LG&E. As part of its application, LG&E proposed its Corporate Policies and Guidelines for Intercompany Transactions for the purpose of expressly establishing the affiliate transaction regulation of LG&E and its affiliates, including its parent corporation. The Commission's May 25, 1990 Order states in part:

> 11. LG&E and each related company shall comply with LG&E's Corporate Policies and Guidelines for Intercompany Transactions.[2]

These Corporate Polices and Guidelines for Intercompany Transactions require the following:

> Holding [the holding company for LG&E and Holding's other subsidiaries] will file consolidated Federal and State income tax returns which will include LG&E's and any other subsidiaries' taxable income. The "stand alone" method will be used to allocate the income tax liabilities of each entity. Payment transfers for tax liabilities or tax benefits will be made on the dates established for the payment of Federal estimated income taxes.[3]

LG&E thus is obliged by the Commission's May 25, 1990 Order to comply with this requirement.

Q. Did the Commission adopt a similar requirement for KU?

A. Yes. The Commission approved an identical requirement (i.e., use of the "stand alone" method to allocate the income tax liabilities of each entity) when KU proposed a similar corporate reorganization and holding company structure in Case No. 10296, *In the Matter of: Application of Kentucky Utilities Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in*

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[2] *In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, Case No. 1989-00374, Order at 20 (May 25, 1990).

[3] Corporate Policies and Guidelines for Intercompany Transactions (LG&E Holding) at 4-5.

Connection Therewith.[4] The Commission required KU and KU Energy Corporation to adhere to similar Corporate Policies and Guidelines, which contained a "stand alone" requirement for computing tax liabilities comparable to the stand alone requirement approved for LG&E.

Thus, the Commission required both companies to adopt and implement similar Guidelines to protect their customers and the utilities themselves from the risks associated with non-utility activities. These Guidelines were intended to ensure that unregulated activities were not subsidized by the utilities or their customers in part by the requirement to follow the stand alone method for computing tax liabilities.

Q. When the Commission approved LG&E and KU's reorganization into holding companies, did the Commission foresee the possibility that their unregulated activities could cause substantial losses?

A. Yes. The Commission clearly anticipated the risk that such unregulated activities might entail, including the possibility of significant losses. This is shown by the requirement in the orders that each holding company, as a condition of approval, be willing to divest the utility in the event that losses on the unregulated side became so great that they posed a risk to the utility operations.[5]

Q. Did the Commission subsequently audit LG&E and KU to determine whether they were in compliance with their respective Corporate Policies and Guidelines?

[4] Corporate Policies and Guidelines for Intercompany Transactions (KU Holding) at 3.

[5] *In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, Case No. 1989-00374, Order at 13-14, 21 (May 25, 1990); *In the Matter of: Application of Kentucky Utilities Company to Enter into an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, Case No. 10296, Order at 12-13,18 (Oct. 6, 1988).

A. Yes. The Commission conducted management audits of KU/KU Energy and LG&E/LG&E Energy. In the management audit report of July 1995 for LG&E/LG&E Energy, the auditors discussed their examination of LG&E's compliance with the requirements of the Commission's Order in Case No. 89-374 and had the following findings:

> <u>XIII-F1</u> "LG&E clearly documents inter-corporate transfers of assets, goods, services and the corresponding financial transactions."
>
> <u>XIII-F4</u> "LG&E has benefited from the exchange of services of Energy Corp."
>
> <u>XIII-F6</u> "Documentation of policies and procedures for intercompany cost allocation and billing is appropriate."
>
> <u>XIII-F7</u> "LG&E's ability to obtain financial resources has not been adversely affected by Energy Corp. or its unregulated affiliates."

In the management audit of KU/KU Energy issued in August 1994, the management auditors made specific reference to the reporting of KU/KU Energy in findings:

> <u>VIII-F1</u> "KU Energy Corporation and its subsidiaries, KU and KU Capital have comprehensive procedures for accounting for intercompany product and service transactions."
>
> <u>VIII-F3</u> "KU has sufficient supporting documentation, policies and guidelines regarding parent and affiliate transactions."

Q. Did the Commission approve new <u>Guidelines</u> that include the "stand alone" requirement in connection with the approval of the LG&E and KU merger?

A. Yes. In its Order of September 12, 1997, in Case No. 97-300, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Merger*, the Commission ordered as follows:

> LG&E, KU and each related company shall, after the merger, comply with LG&E Energy's Corporate Policies and Guidelines for Intercompany Transactions.

Order, p. 39. LG&E Energy's <u>Corporate Policies and Guidelines for Intercompany Transactions</u> expressly state:

> LG&E Energy will file consolidated Federal and State income tax returns which will include LG&E's, KU's and any other subsidiaries' taxable income. The "stand alone" method will be used to allocate the income tax liabilities of each entity. Payment transfers for tax liabilities or tax benefits will be made on the dates established for the payment of Federal estimated income taxes.[6]

Rives Rebuttal Exhibit 1 contains an accurate copy of the LG&E, KU, and LG&E/KU Guidelines.

Q. Did the Commission require LG&E and KU to continue to follow the <u>Guidelines</u> as condition to the approval of the PowerGen merger with LG&E Energy Corp.?

A. Yes. In its Order of May 15, 2000, in Case No. 2000-095, *In the Matter of: Joint Application of PowerGen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Merger*, in Appendix B the Commission ordered as follows:

> LG&E and KU should continue to comply with their <u>Corporate Policies and Guidelines for Intercompany Transactions</u> as well as employing other procedures and controls related to sales, transfers and cost allocation to ensure and facilitate the full review by the Commission and protection against cross-subsidization.

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[6] Corporate Policies and Guidelines for Intercompany Transactions (LG&E Energy) at 5.

Thus, again, the Commission affirmed the Guidelines and the stand-alone method requirement therein.

Q. Did the Commission require LG&E and KU to continue to follow the Guidelines as a condition to the approval of the E.ON acquisition of PowerGen?

A. Yes. In its August 6, 2001 Order in Case No. 2001-104, *In the Matter of: 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 Commission required as a condition of its approval of the acquisition and transfer of ownership and control of LG&E and KU the acceptance of the following Commitment and assurance:

> E.ON, Powergen, LG&E Energy, LG&E and KU shall adhere to the conditions described in the Commission's Orders in Case Nos. 10296, 89-374, 97-300 and 2000-095 to the extent those conditions are not superseded by KRS 278.2201 through 278.2219 or the jurisdiction of the SEC or FERC. These conditions, restated in Appendix B to the Commission's May 15, 2000 Order in Case No. 2000-095, concern protection of utility resources, monitoring the holding company and the subsidiaries and reporting requirements.

Order (May 6, 2001), Appendix A - No. 1.

Q. Has the Commission followed and applied the Guidelines in connection with ratemaking decisions?

A. Yes. In its June 20, 2005 Orders in Case Nos. 2004-00421 and 2004-00426, when approving LG&E and KU's 2004 Environmental Surcharge applications, the Commission determined that the Guidelines required LG&E and KU to transfer emission allowances at cost for purposes of implementing the proposed environmental surcharges: "The Guidelines clearly require that the transfer or sale of assets between LG&E and KU will be priced at cost."[7] The Commission further noted in those Orders, "The Commission ordered LG&E and KU to comply with the Guidelines after the merger."[8]

Also, in its June 11, 2002 Order in Case No. 2002-00029, the Commission determined that the Guidelines required LG&E and KU to transfer combustion turbines ("CTs") and associated property at cost: "The Commission agrees that the CTs should be priced at cost and finds that LG&E and KU should file their final determination of the cost of the transferred CTs within 30 days after the date of the transfer. The determination should be in accordance with the requirements of ... LG&E Energy's Corporate Guidelines."[9]

Q. Please describe the stand-alone method.

A. The stand-alone method is based upon the following three closely related accounting and regulatory principles: (1) cost causation; (2) the benefits-burden relationship; and (3) prevention of cross-subsidies with affiliates. In other words, a utility's rates are set to recover the just and reasonable costs of providing utility service as adjusted in the rate case test year. The cost of income taxes allowed for recovery through rates, therefore, should be directly related to the revenues earned and costs incurred in providing utility service. In short, there should be a link or match between allowed

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[7] *In the Matter of: The Application of Louisville Gas and Electric Company for Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2004-00421, Order at 12 (June 20, 2005); *In the Matter of: The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct Flue Gas Desulfurization Systems and Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2004-00426, Order at 16 (June 20, 2005).
[8] *In the Matter of: The Application of Louisville Gas and Electric Company for Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2004-00421, Order at 12 n.22 (June 20, 2005); *In the Matter of: The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct Flue Gas Desulfurization Systems and Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2004-00426, Order at 15 n.30 (June 20, 2005).
[9] *In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Acquisition of Two Combustions Turbines*, Case No. 2002-00029, Order at 7 (June 11, 2002)

income tax expense and regulatory utility service. The stand-alone method, emphatically approved by this Commission for over eighteen years, ensures this relationship by computing tax expense directly on test year revenues and costs.

Q. How does this compare with KIUC's recommendation?

A. KIUC's approach would treat each of LG&E and KU completely inconsistently from the Commission's stand-alone method of regulation. Under KIUC's approach, the losses of an unregulated affiliate, which generate tax savings in a consolidated tax return and thus lower the consolidated tax liability, are used to effectively create a windfall benefit to the utilities' customers.

Q. How would KIUC's proposal confer a windfall benefit on the utilities' customers?

A. The tax benefits of the unregulated affiliate are the direct result of the actual losses sustained by the unregulated business. Consistent with the procedure to insulate the regulated entities from potential unregulated losses, utility customers did not suffer these losses and did not pay the costs of these losses. Because utility customers did not incur or pay for these losses, they should have no claim on the tax benefits associated with the losses. KIUC's proposal, however, would do just that: give customers the tax benefits of losses for which they did not pay nor bear any risk.

The tax losses associated with the unregulated affiliate belong to the owners of the affiliate who invested in the enterprise in exchange for the potential gain and at the risk for the potential loss. The tax savings created by tax losses associated with unregulated affiliate belong to the shareholders of the unregulated affiliate, which sustained the losses.

Q. Please explain what the benefits-burden relationship principle is, how the Commission has followed it in the past, and how KIUC's proposed consolidated tax-related income adjustment violates the principle.

A. The benefits-burden principle provides that reward should follow risk and benefits should follow burden. The Commission used this principle in connection with its analysis of the disposition of the proceeds from the sale of KU's railcars in a fuel adjustment case several years ago to conclude that, because ratepayers had paid the depreciation expense associated with the railcars, the ratepayers were entitled to the proceeds.[10] Though the filing of a consolidated return may result in tax offsets on a consolidated basis, the tax offsets only occur because certain members of the consolidated group have incurred losses offsetting the gains of other members of the consolidated group. These entities that achieve the benefits of the net operating losses are entitled to retain the benefits because these entities, and not LG&E's or KU's customers, incurred the expenses that resulted in taxable losses. These expenses were not included in the utility cost of service or recovered through rates.

The financing costs associated with the PowerGen PLC acquisition of LG&E Energy Corp. and E.ON AG's acquisition of PowerGen PLC are another example of the benefit-burden principle. In each of the cases approving the transactions, the Commission expressly stated that these costs could not be recovered from the utilities' customers. These costs were borne by the shareholders who were thus entitled to the tax benefit (i.e., the tax deduction of the expense from income).

[10] *In the Matter of: An Examination By the Pubic Service Commission of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company From November 1, 1990 to October 31, 1992*, Case No. 1992-00493, Order at 20 (January 2, 1997)

Under KIUC's consolidated approach, however, part of the shareholders' benefit for bearing the risk of its unregulated investments is confiscated for purpose of reducing customers' rates.

Q. **Please explain the principle preventing cross-subsidies between Commission-regulated and unregulated businesses, and how KIUC's proposed consolidated tax approach would violate it.**

A. Yes. As I previously discussed in my testimony, the Commission has permitted the parent companies of LG&E and KU to pursue unregulated businesses; however, there has always been a stipulation that there should be no cross-subsidization between regulated and unregulated businesses. If a utility's income tax expense is not calculated on a stand-alone method, but instead is adjusted using consolidated tax savings, the separation between a utility and its affiliates will be completely compromised. In order to prevent cross-subsidies, all regulated and unregulated members of a consolidated group should be treated fairly and equitably.

Q. **Would acceptance of Mr. Kollen's recommendation jeopardize the ability of LG&E and KU to achieve their authorized rates of return?**

A. Yes. Mr. Kollen's recommendation would preclude LG&E and KU from achieving their authorized rates of return because the recommendation would result in an imputed, as opposed to an actual, benefit. The only way to reflect the adjustment is to reduce revenues with absolutely no offsetting benefit. If all other revenue and expense items remain the same, diminished revenues will result in a rate of return that is necessarily less than authorized. LG&E and KU would not have a meaningful opportunity to earn a reasonable return on their capital invested in facilities to serve customers. The impact of such an adjustment could also affect LG&E and KU's abilities to raise capital at reasonable and cost-effective rates because investors would view the adjustment as an effective discount to the allowed rate of return.

Q. Is there an authoritative accounting source that addresses the stand alone method?

A. Yes. The text Accounting for Public Utilities by Robert L. Hahne and Gregory E. Aliff is a widely accepted and authoritative source in public utility accounting matters. This book states:

> *Consolidated tax results* - It is not uncommon for a regulated utility to have subsidiary operations that produce tax losses which, on a consolidated tax return, offset taxable income from utility operations. Over the years, many have disagreed about how to allocate these taxes. One approach has been to use "effective tax rates," whereby the income tax benefits of affiliated company losses are used to reduce the tax costs of the utility. The only approach that is consistent with standard ratemaking principles that prohibit cross-subsidization between utility and non-utility activities is to put the regulated operation on a "stand alone" basis and to assign the full tax burden to the taxable gain source and a tax benefit to the tax loss source. The basic theory is that the regulated costs should not be affected by the results from nonregulated operations.[11]

The book further states:

> Income tax normalization is consistent with a fundamental principle of the cost of service approach to ratemaking; the principle that consumers should bear the only costs for which they are responsible. Under this principle, there is a well-reasoned, and widely recognized, postulate that taxes follow the events they give rise to. Thus, if ratepayers are held responsible for costs, they are entitled to the tax benefits associated with the costs. If ratepayers do not bear the costs, they are not entitled to the tax benefits associated with the costs.
>
> Regulators have long used a ratemaking procedure that explicitly embraces this principle. The procedure is to identify utility activities (revenues and costs) and compute taxes directly related to the utility activities.

[11] Hahne and Aliff, Accounting for Public Utilities § 7.08[3].

> Non-utility operations involve financial risks that are different from a utility's regulated operations. When these risks are not borne by the ratepayers, it is unfair to make use of the business losses generated in those nonregulated entities to reduce the utility's cost in determining the rates to be charged for utility services. By the same token, when a company's nonjurisdictional activities are profitable, the ratepayers have no right to share in those profits, but neither are they required to pay any of the income taxes that arise as a result of those profits. Thus, a "stand alone" method (as opposed to a consolidated effective tax rate method) for computing the income tax expense component of cost of service is the proper and equitable method to be followed for ratemaking purposes.[12]

Q. Do a majority of state commissions use the stand-alone approach?

A. Yes. It is noteworthy that Mr. Kollen could list only five states that have adopted the consolidated approach; the simple reason for such a short list is that the great majority of states continue to use the stand-alone approach for the reasons I have discussed above. Concerning those states that have adopted the consolidated approach, in recent testimony before the New Mexico Public Regulation Commission ("NMPRC"), a member of the NMPRC staff, who had investigated these two approaches from a neutral position, had the following to say:

> Adoption of the consolidated method appears to have been a policy decision not necessarily related to accounting and regulatory principles. ... [A] better and sounder policy is to treat all members of the consolidated group equitably and to establish utility costs of taxes on a stand alone basis.[13]

Virginia is one state that recently has adopted as a matter of statutory law the "better and sounder policy" of using the stand-alone method. Last year, the Virginia legislature amended VA Code § 56-235.2 to add the following language, which unambiguously endorses the stand-alone method:

[12] Hahne and Aliff, Accounting for Public Utilities § 17.06[3].

> For ratemaking purposes, the Commission shall determine the federal and state income tax costs for investor-owned water, gas, or electric utility that is part of a publicly-traded, consolidated group as follows: (i) such utility's apportioned state income tax costs shall be calculated according to the applicable statutory rate, as if the utility had not filed a consolidated return with its affiliates, and (ii) such utility's federal income tax costs shall be calculated according to the applicable federal income tax rate and shall exclude any consolidated tax liability or benefit adjustments originating from any taxable income or loss of its affiliates.[14]

Indeed, the state commissions in New Mexico and Minnesota recently issued orders rejecting the consolidated income tax approach and affirmatively approving the stand alone method as the superior approach to preventing cross subsidization and protecting the utility's assets. The Commission should therefore continue to reaffirm its long-standing commitment to remain among the vast majority of states that adhere to sound rate-making principles by approving the Companies' use of the stand-alone method. KIUC has presented no valid or sound reason that justifies an abrupt and radical departure.

Q. Are you familiar with the consolidated income tax adjustment the Commission approved in its February 28, 2005 Order in Case No. 2004-00103, *In the Matter of: Adjustment of the Rates of Kentucky-American Water Company*? If so, please describe your understanding of that adjustment.

A. Yes. In Case No. 2004-00103, Kentucky American Water ("KAW") sought recovery of its income tax expense based on the federal statutory rate of 35% of its taxable income. The AG retained Andrea Crane as an expert witness and she proposed a consolidated income tax adjustment based on the fact that KAW files its federal taxes

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[13] *In the Matter of the Application of Public Service Company of New Mexico for a Revision of Its Retail Electric Rates Pursuant to Advice Notice No. 334*, New Mexico Public Regulation Commission Case No. 07-00077-UT, Prepared Direct Testimony of Charles W. Gunter at 23-24 (Oct. 22, 2007).

[14] VA Code § 56-235.2(A).

as part of a consolidated group. In her direct testimony, Ms. Crane proposed that because KAW files its federal tax returns as a member of a consolidated group, any tax benefits or savings realized by any member of the group should be enjoyed by KAW customers on an allocated basis.

Q. **Did KAW oppose the consolidated tax adjustment?**

A. Yes. KAW filed rebuttal testimony in which its expert witness explained that KAW, which has always had taxable income, always writes a check to its parent company for 35% of its taxable income that is then used for payment of federal taxes by the consolidated group. He explained that to the extent that any other member of the group has a tax loss, KAW never receives any benefit of that loss. The witness further explained that taking a benefit "earned" by one member of the group and giving some of that benefit to KAW is a "cross-subsidy" in that the Commission would be taking a benefit from an entity it does not regulate and giving it to an entity it does regulate.

Q. **Did the Commission accept the proposed consolidated tax adjustment in that case?**

A. Yes. The Commission held that the consolidated tax adjustment should be approved and reduced KAW's federal income tax expense by the amount proposed. However, the February 28, 2005 Order in Case No. 2004-00103 is clear that the Commission did not accept the adjustment on the basis that it generally favors or agrees with the consolidated tax adjustment concept. Instead, the lynchpin of the holding was that the Commission believed that KAW had committed in an earlier case that it would realize tax *savings* by virtue of being a member of a consolidated tax filing group.

> We find that Kentucky-American's present position on this issue conflicts with its stated position in Case No. 2002-00317.

> In that proceeding, Kentucky-American and others sought approval of the transaction that enabled RWE's acquisition of control of Kentucky-American. One feature of this transaction was the creation of TWUS, an intermediate holding company that would hold the stock of American Water and all of Thames Water Aqua Holdings GmbH's other U.S. affiliates. Kentucky-American asserted the creation of TWUS would permit the filing of consolidated U.S. tax returns. The ability to file such a tax return, Kentucky-American argued, benefited the public because it would reduce administrative expenses by eliminating the need to file multiple tax returns and permit some tax savings by allowing payment of taxes calculated on the net profits of all entities within the consolidated group.
>
> . . .
>
> Having previously indicated the savings resulting from the filing of a consolidated tax filing would be viewed as a merger benefit, subject to allocation, we do not believe that acceptance of the AG's proposal represents a radical departure from past regulatory practice. Moreover, Kentucky-American and its corporate parents having previously touted TWUS's filing of consolidated tax returns as a benefit to obtain approval of the merger transaction, have no cause to object if we now act upon their representation. Accordingly, we find that the AG's proposed consolidated income tax is reasonable and have reflected it in our calculation of federal income taxes.[15]

Q. Has LG&E ever represented that a benefit of any of its mergers would be to calculate taxes on a consolidated basis for rate-making purposes?

A. No, neither LG&E nor any of the entities with which it has merged has ever represented that a merger benefit would be calculating income taxes on a consolidated basis for rate-making purposes, nor has the Commission or any other party ever asserted otherwise. In fact, in their merger KU and LG&E specifically adopted, with Commission-approval, the stand-alone method in their policies and procedures. Therefore, there is no support for such a rate-making calculation in this proceeding.

[15] *In the Matter of: Adjustment of the Rates of Kentucky-American Water Company*, Case No. 2004-00103, Order at 64-66 (Dec 28, 2005).

Q. Are you aware that the Commission again addressed the issue of a consolidated tax adjustment in the rehearing phase of LG&E's 2003 rate case?

A. Yes. In its March 31, 2006 Order on Rehearing in Case No. 2003-00433 (*In the Matter of: An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*), the Commission rejected the use of a consolidated group driven "effective" state tax rate in computing Kentucky income tax expense. In that case, LG&E argued that Kentucky's statutory rate should be used to calculate Kentucky income tax expense. The AG argued in favor of using an effective tax rate that resulted from LG&E's participation in a consolidated tax filing group. The AG cited the KAW decision above as "precedent" for use of an effective tax rate. The Commission rejected the AG's argument. The Commission decided that using an "effective" rate could well be viewed as forcing the utility to use unregulated activities to subsidize the regulated utility's operations:

> The Commission has previously expressed concerns about using an effective Kentucky income tax rate due to the annual fluctuations in the effective rate. These fluctuations occur because the effective Kentucky income tax rate is determined from the total of all the tax income and tax losses of all the entities that file on the same consolidated income tax return. For LG&E, the majority of the entities other than KU included in the consolidated income tax return of LG&E's parent corporation, E.ON US Investment Corp., reflect activities which are not regulated by the Commission. By having to recognize tax losses and other tax credits related to these non-regulated activities to derive an effective Kentucky income tax rate could well be viewed as forcing the utility to use these non-regulated activities to subsidize the regulated utility operations. There is also a concern that because of the way the apportionment of certain tax transactions is performed, the resulting effective Kentucky income tax rate could exceed the statutory Kentucky income tax rate. Thus, establishing the effective tax rate as the guideline or precedent, as the AG has requested on rehearing, could in the future result in higher utility rates to pay for taxes on non-regulated activities.

> . . .
>
> The Commission further finds it reasonable to continue using the statutory Kentucky income tax rate for determining LG&E's revenue requirements in this case. The statutory Kentucky income tax rate is known and measurable and is not subject to fluctuations due to non-regulated tax losses or tax credits, or due to apportionment adjustments from non-regulated activities. The Commission has consistently utilized the statutory Kentucky income tax rate to determine utility revenue requirements absent an agreement or representation to the contrary by the utility.[16]

Q. Should the Commission set aside the stand-alone tax methodology that has been in place for the past eighteen years in order to reduce rates in this case?

A. No. Unwinding this policy and the associated cost allocation principles to reach a specific result in this case would undermine the Commission's heretofore consistent policy preventing cross-subsidization between regulated and unregulated businesses, and would also do violence to the basic market economic principle that benefit should follow risk. It is for this reason that the Commission adopted many years ago and continues to insist upon the stand-alone methodology.

Moreover, nothing has changed in the eighteen years since the Commission adopted the stand-alone income tax concept to support a change in methodology. The Commission has reviewed this tax issue many times and in each instance the Commission has, for good reason, concluded that the stand alone concept should remain.

Q. Do you agree with Mr. Kollen's assertion that LG&E and KU should be compensated for their "loans and/or grants to E.ON and its loss subsidiaries?"

A. No. The assertion contains a false premise, namely that the payments are loans or grants at all rather than payments made for value. This is absolutely not the case.

Since the formation of their holding company structures, LG&E's and KU's unregulated activities have experienced both gains and losses. In those years where the unregulated activities generated profits or gains, they were not shared with the utilities' customers. Of equal, if not more, importance is the fact that in those years where the unregulated activities have experienced losses, customers have not been charged for those losses. When the unregulated activities experience gains and paid income taxes associated with those gains, customers of LG&E and KU were not charged that tax expense. Given that customers will pay through LG&E's proposed rates exactly the tax expense they would have to pay if LG&E were a stand-alone utility in return for not being charged tax expenses when the unregulated activities experience gains and pay income taxes associated with those gains, there simply will be no money for a "grant" or "loan." The stand-alone method requires the utilities to pay the same amount of income tax as if they were separate entities – no more, no less. It is necessary to separate completely the regulated and unregulated entities, consistent with the Commission-approved Guidelines.

In this case, the most significant principle is maintaining the long-standing division between LG&E's Commission-regulated and unregulated businesses, of which the stand-alone tax methodology is an integral part. The Commission should refuse Mr. Kollen's invitation to abandon its principles by rejecting his proposed consolidated tax adjustment. The Commission has refused this kind of short-run ratemaking in the past out of well-grounded concern for the prejudice to the ratepayers in the long run.[17]

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[16] *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, Order at 8-9 (March 31, 2006).

[17] *In the Matter of: Big Rivers Electric Corporation's Proposed Mechanism to Credit Customers Amounts Recovered in Judicial Proceedings Involving Fuel Procurement Contracts*, Case No 94-453, Order, pp. 7-8

ECR Rate Base Allocation of Capitalization

Q. What is the purpose of your discussion below concerning LG&E's proposal to allocate capital based on ECR rate base?

A. The purpose of my testimony is to address the statements made by Mr. Henkes for the AG and Mr. Kollen for the KIUC regarding the allocation of ECR rate base against Company capitalization and to point out a fundamental error in the previous ECR rate base adjustment to capitalization adjustment methodology employed by the Commission in Case No. 2003-00433 and cases prior. I originally addressed this issue in my testimony for LG&E on pages 26 and 29-32, wherein I explained LG&E's proposed methodology for ensuring that ECR investment is appropriately considered in the determination of base rates.

Q. Messrs. Henkes and Kollen state that the Commission approved the capitalization allocation methodology they propose in LG&E's most recent rate case, Case No. 2003-00433. Why does LG&E propose a methodology in this rate case that differs from the Commission's previously established methodology?

A. In its September 7, 2007 Order in Case No. 2007-00179, the Commission indicated that a base rate case is the appropriate forum for evidence on the matter of the ECR adjustment to capitalization.[18] Because this is the first base rate case LG&E has filed since Case No. 2007-00179, LG&E is presenting its concerns about the current methodology in this case. Also, because Messrs. Henkes and Kollen have provided testimony on this issue, I am addressing their positions.

Q. Why does LG&E disagree with the current Commission methodology?

(February 21, 1997)(" While a refund of any litigation proceeds may be attractive in the short run, in the long run the precedent which it establishes may greatly disadvantage utility ratepayers. ").

A. LG&E disagrees with the current Commission methodology for adjusting capitalization with respect to ECR rate base because it reduces capitalization by an amount in excess of ECR rate base. When LG&E calculates ECR rate base for its ECR filings, it reduces ECR plant investment by depreciation and deferred taxes. This is an appropriate calculation because depreciation and deferred taxes are rate-making reductions in the calculation of rate base;[19] however, it is erroneous not to use that same ECR rate base amount to reduce capital, which is the error in the current capitalization allocation methodology. In other words, the current Commission capitalization methodology errs by deducting from capitalization an amount greater than LG&E's ECR rate base, and the excess that it deducts is the amount of the deferred taxes associated with ECR rate base. The result of this error is denying LG&E recovery on a portion of its invested capital in an amount equal to its deferred taxes associated with ECR rate base.

Q. Where does Mr. Henkes err in his discussion of the current capitalization allocation methodology?

A. Mr. Henkes errs by failing to correctly address the impact of deferred income taxes on rate base and capitalization,[20] and attempts to make much of a quote from a Commission order in Case No. 1998-00426, "LG&E has acknowledged the PC DIT are not funded by its capitalization ...."[21] Though it is true that deferred income taxes are not directly *funded* by LG&E's capitalization, there is more of rate-making import

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[18] *In the Matter of: Application of Louisville Gas and Electric Company for an Order Authorizing Inclusion of Investment Tax Credits in Calculation of Environmental Surcharge and Declaring Appropriate Ratemaking Methods for Base Rates*, Case No. 2007-00179, Order at 9-10 (Sept. 7, 2007).

[19] As an Option 1 company, KU's reduces its rate base by its ITCs. As an Option 2 company, LG&E does not reduce its rate base by ITCs, but instead includes an amortization of its ITCs in its cost of service calculation. Both methods are acceptable under the Internal Revenue Code. *See* 26 U.S.C. § 50(d)(2) (continuing in effect companies' elections under now-repealed 26 U.S.C. § 46(f)).

[20] Henkes LG&E Electric Testimony at 9-11.

to say about the impact of deferred taxes on both rate base and capitalization. When LG&E monetizes deferred taxes, they effectively reduce capitalization. The calculation of rate base includes a reduction in the same amount. As shown on LG&E's reconciliation of rate base and capitalization,[22] deferred taxes are not reconciling items between rate base and capitalization; because they affect both rate base and capitalization in the same way, they cannot be reconciling items. The current methodology unfortunately treats them differently by correctly including deferred taxes in the calculation of ECR rate base for ECR filings but incorrectly excluding the very same ECR deferred taxes in the adjustment to capitalization used to set base rates. This methodology in effect reduces LG&E's investment twice for the same deferred tax amounts: once correctly in the ECR rate base amounts and once incorrectly in the adjustment to capitalization.

Q. Does Mr. Kollen agree with your assessment of the current methodology?

A. Mr. Kollen agrees that the ECR rate base adjustment to capitalization should be "100% of ECR rate base," which the KIUC confirmed in its response to one of LG&E's data requests.[23] The current methodology, however, reduces capitalization by more than 100% of ECR rate base.

Q. Can you provide an example showing how the current methodology adjusts capitalization by more than 100% of ECR rate base?

A. Yes. In Appendix B of my direct testimony, I included a schedule that adjusted capitalization by the current methodology. (Please note that my original testimony indicated this Appendix was provided as an informational matter and was not being

[21] *In the Matter of: Application of Louisville Gas and Electric Company for Approval of an Alternative Method of Regulation of Its Rates and Service*, Case No. 1998-00426, Order at 4 (June 1, 2000).
[22] *See* Case No. 2008-00252, LG&E Application Tab 28.

adopted as a reasonable allocation method. That qualification remains in place in this rebuttal testimony.) On page 2, column 6 of Appendix B, you see capitalization reduced by $16,802,860, which represents the current methodology's deduction of ECR rate base adjusted for deferred taxes associated with ECR rate base; however, the actual amount of net ECR rate base as of 4/30/2008 is $13,285,453, as shown on Exhibit 3, page 1, column 5 of my direct testimony.[24] (Again, the KIUC has clearly stated it agrees with LG&E's calculation of the actual amount of net ECR rate base as of 4/30/2008.)[25] If the error continues, LG&E will be denied a return on $3,515,427 of capital (the incorrect adjustment of $16,802,860 minus the correct adjustment of $13,285,453) that has been invested to serve its customers. This denial will be caused by a calculation error rather than any intentional disallowance, but the net result will still be confiscatory and without support.

Q. **Must the Commission adopt LG&E's new allocation methodology to correct the error you have described?**

A. The Commission does not have to adopt the alternative approach, but the error should be corrected; the Commission should adjust capitalization by 100% of ECR rate base, as Mr. Kollen has confirmed, not by more than 100%.

Nonetheless, LG&E believes its proposed allocation methodology is more appropriate than the one currently in place because it is simple, straightforward, and accurate, and produces a reasonable result without the need to make an additional

[23] Kollen LG&E Testimony at 42; Response of KIUC to LG&E's First Set of Data Requests, DR No. 1-11 (Dec. 3, 2008).

[24] Note that the ECR filing for April ES Form 2.00, line 25 includes the amount shown in Column 3 of my Exhibit 3 ($232,485,247) and the roll-in amount in column 4 of my Exhibit 3 can be tied directly to the Commission's March 28, 2008 Order on roll-in in Case No. 2007-00380. The net of these two amounts represents the remaining ECR rate base not included in base rates as of 4/30/2008 and it equals the $13,285,453 shown in column 5 of my Exhibit 3.

[25] Response of KIUC to LG&E's First Set of Data Requests, DR No. 1-11 (Dec. 3, 2008).

adjustment to capitalization. As I noted in my previous testimony, the Commission has used this methodology to allocate the capital supporting retail base rates in LG&E's and KU's rate cases for years. LG&E has used this methodology to allocate the appropriate amount of capital between electric and gas operations for years. LG&E's sister company, KU, has used this same methodology for many years to allocate the appropriate amount of capital to Kentucky and Virginia retail jurisdictions and wholesale jurisdictions. Allocating the capital supporting ECR rate base from the Company's overall capitalization using the rate base allocation methodology is consistent with the use of this allocation methodology to allocate the appropriate amount of capital supporting electric and gas operations for base rate purposes, or allocating capitalization to the Kentucky jurisdiction for base rate making purposes. Not including the ECR rate base as part of the determination of the rate base allocation percentages is inconsistent with this well-established ratemaking method.

Reduction to Capitalization Due to Collection Cycle Change

Q. Mr. Kollen states in his testimony that if the Commission grants LG&E's request to reduce the due date of its bills from fifteen to ten days from the bill date, the Commission should also reduce LG&E's capitalization to account for the accelerated cash flow he asserts will result from the due date change. On that basis, he proposes to reduce LG&E's revenue requirement by $810,000. Do you agree with Mr. Kollen's analysis?

A. No, I do not agree with his analysis. First, other than bare assertion, Mr. Kollen presents no basis upon which to believe that reducing the due date of LG&E's bills from fifteen to ten days will accelerate LG&E's cash flow. He has not performed a lead-lag study or any other objective analysis to support his conclusions, so that his proposed adjustment is not in fact based on "known and measurable" changes.[26]

Second, even as an intuitive matter it makes little sense to suppose that LG&E's proposed collection cycle change will accelerate *all* of its revenues by five days, particularly because LG&E has not proposed to change the date on which it will assess late fees, which will remain fifteen days from the bill date. For example, those who currently pay late will have no additional incentive to pay five days earlier under LG&E's proposed collection cycle change. Also, those who currently pay on the tenth through the fourteenth days after their bill dates will have no economic motivation to change that practice.

Third, Mr. Kollen's proposed adjustment is for unknowable and immeasurable events and circumstances that cannot even begin to occur until the Commission enters a final order in this proceeding. For that reason, if the Commission approves LG&E's proposed collection cycle and it indeed affects the timing of payments LG&E receives, it will be appropriate to address the subject in LG&E's next base rate case, not in this proceeding.

Rate Base Calculation

Q. Mr. Henkes proposes an adjusted electric original cost rate base of $1,824.594 million, which is $29.372 million higher than LG&E's proposed electric pro forma rate base of $1,795.222 million. Do you agree with the adjustments Mr. Henkes made to arrive at his adjusted electric original cost rate base for LG&E?

A. I agree with two of the adjustments Mr. Henkes made to arrive at his adjusted electric original cost rate base for LG&E, but I do not agree with the most significant

[26] Response of KIUC to LG&E's First Set of Data Requests, DR No. 1-9 (Dec. 3, 2008).

adjustment Mr. Henkes made, an adjustment to LG&E's depreciation reserve. LG&E agrees with Mr. Henkes that, per LG&E's response to Data Request No. 13 of the Attorney General's First Data Request in this proceeding, it is correct to remove from prepayments added to rate base the fees LG&E pre-paid to the Commission, which reduces LG&E's electric rate base by about $502,000.[27] LG&E likewise agrees with Mr. Henkes that, as stated in LG&E's response to Data Request No. 15 of the Attorney General's First Data Request in this proceeding, it is correct to remove depreciation and taxes from the calculation of cash working capital, which reduces LG&E's electric rate base by about $3.0 million, which is a reduction $2.212 million greater than that contained in LG&E's filed pro forma rate base.[28]

Mr. Henkes's most significant proposed adjustment to LG&E's electric original cost rate base, however, is incorrect. First, he asserts that $15.363 million should be added to rate base due to the Attorney General's proposed depreciation reserve adjustment, which results from the AG's proposed depreciation rates. LG&E's proposed depreciation rates, on the other hand, would reduce the electric depreciation reserve by $16.723 million. LG&E witness John Spanos discusses the reasons why LG&E's proposed Equal Life Group depreciation rates should be adopted rather than those proposed by the AG. If the Commission agrees with LG&E about those rates, it should reject the AG's proposed depreciation rates and their attendant depreciation reserve adjustment.

Q. Mr. Henkes proposes an adjusted gas original cost rate base of $445.619 million, which is $7.1333 million higher than LG&E's proposed gas pro forma rate base

[27] *See* Henkes LG&E Electric Testimony at 13-14.
[28] *See* Henkes LG&E Electric Testimony at 14-15.

of $438.486 million. Do you agree with the adjustments Mr. Henkes made to arrive at his adjusted gas original cost rate base for LG&E?

A. I agree with two of the adjustments Mr. Henkes made to arrive at his adjusted gas original cost rate base for LG&E, but I do not agree with the most significant adjustment Mr. Henkes made, an adjustment to LG&E's depreciation reserve. LG&E agrees with Mr. Henkes that, per LG&E's response to Data Request No. 13 of the Attorney General's First Data Request in this proceeding, it is correct to remove from prepayments added to rate base the fees LG&E pre-paid to the Commission, which reduces LG&E's gas rate base by about $195,000.[29] LG&E likewise agrees with Mr. Henkes that, as stated in LG&E's response to Data Request No. 16 of the Attorney General's First Data Request in this proceeding, it is correct to remove depreciation and taxes from the calculation of cash working capital, which increases LG&E's gas rate base by about $88,000, which is an increase $430,000 less than that contained in LG&E's filed pro forma rate base.[30]

Mr. Henkes's most significant proposed adjustment to LG&E's gas original cost rate base, however, is incorrect. First, he asserts that $4.269 million should be added to rate base due to the Attorney General's proposed depreciation reserve adjustment, which results from the AG's proposed depreciation rates. LG&E's proposed depreciation rates, on the other hand, would reduce the gas depreciation reserve by $3.489 million. LG&E witness John Spanos discusses the reasons why LG&E's proposed Equal Life Group depreciation rates should be adopted rather than those proposed by the AG. If the Commission agrees with LG&E about those rates, it

[29] *See* Henkes LG&E Gas Testimony at 10-11.
[30] *See* Henkes LG&E Gas Testimony at 10.

should reject the AG's proposed depreciation rates and their attendant depreciation reserve adjustment.

Operating Income Adjustment

Q. Why is Mr. Henkes incorrect in asserting that LG&E's proposed New Bank Credit Facilities Adjustment is not known and measurable?

A. The fees associated with the letters of credit that were included in the original filing were estimates. However, the fees have now been negotiated with the letter of credit bank for KU and incorporated into the documents that will be signed during December. The 70 bps fee included in the most recent data response is the fee included in the KU documents which is now firm. In addition, the dollar amount of the bonds that will be backed by letters of credit has not changed from the $211.335 million as included in the original filing. The bank LG&E had been working with on this matter has recently withdrawn its offer due to the volatility of the financial markets. Based on current market conditions, the cost will be at least the 70 bps requested in the adjustment. Mr. Henkes himself has included these amounts as part of his recommendation which is further evidence that the costs are known and measurable. Further details of the transaction will be provided prior to the hearing in this proceeding.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **S. Bradford Rives**, being duly sworn, deposes and says he is the Chief Financial Officer for Louisville Gas and Electric Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

SBRives

S. BRADFORD RIVES

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of December, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

Rives Rebuttal Exhibit 1

LG&E/LG&E Energy

Corporate Policies and Guidelines for Intercompany Transactions

Corporate Policies and Guidelines for Intercompany Transactions

These Policies and Guidelines have been established to set forth business practices to be observed in transactions between Louisville Gas and Electric Company (LG&E), its proposed Holding Company ("Holding") and any nonutility subsidiary created by Holding. As nonutility subsidiaries are created by Holding, these policies and guidelines will be revised and expanded to ensure that the non-regulated activities are not subsidized by LG&E's ratepayers. Updated policies and guidelines will be filed with the Public Service Commission on an annual basis.

Policies and Guidelines

1. Separation of costs between utility and non-utility activities will be maintained.

Distinct and separate accounting and financial records will be maintained and fully documented for each entity. All costs, which can be specifically identified and associated with an activity, will be directly assigned to that activity. Indirect costs, which provide a benefit to more than one activity, will be allocated to the activities that receive a benefit.

Although initially there will be a sharing of resources between LG&E and Holding, to the extent practicable, each subsidiary of Holding will acquire and maintain its own facilities, equipment, staff and financing.

2. <u>Intercompany transactions shall be structured to ensure that non-regulated activities are not subsidized by the regulated utility</u>.

Separate accounting and financial records will be maintained to ensure that intercompany transactions related to non-utility activities will not have an adverse impact on the utility or its customers.

Transfers or sales of assets will be priced at the greater of cost or fair market value for transfers or sales from LG&E to Holding or other subsidiaries and at the lower of cost or fair market value for transfers or sales made to LG&E from Holding or any of its subsidiaries. Settlement or transfer of liabilities will be accounted for in the same manner. Through this policy, the utility will receive the full benefit from intercompany transfers or sales.

LG&E shall furnish a report to the PSC annually of each transfer of utility assets between LG&E and Holding or any of its subsidiaries, which has a value of $250,000 or more. Transfers having a value of less than $250,000 will be grouped and reported by specific categories, such as transportation equipment, power operated equipment, etc.

Transfers or sales of nonutility assets, payment of dividends and normal recurring transactions are expressly excluded from this reporting requirement.

All good or services provided by the utility to Holding or any of its subsidiaries will be billed at cost, including the proper assignment of all indirect costs.

LG&E will utilize its automated responsibility accounting system to accumulate and allocate costs among the various companies. To the extent possible, specific activities or projects will be directly recorded in the accounting and financial records of the appropriate company. Transactions affecting more than one entity will be allocated among the affected companies by reference to some reasonable, objective standard related to the facts and circumstances of the transaction (i.e., number of employees, number of transactions, etc.)

Billings for intercompany transactions shall be issued on a timely basis with documentation sufficient to provide for subsequent audit or regulatory review. Payments for intercompany transactions shall be made within thirty (30) days of receipt of the invoice. If payment is not made by the due date, late charges will be assessed by the billing company.

3. <u>Strict internal controls will be maintained to provide reasonable assurance that intercompany transactions are accounted for in accordance with management's policies and guidelines</u>.

Accounting policies and procedures for intercompany transactions will be fully documented and provided to all entities.

Intercompany transactions will be fully documented in sufficient detail to enable verification of the relevant information. Periodic audits will be made of intercompany transactions and transfer prices to ensure that these policies and guidelines are being observed. Any detected deviations from these policies and guidelines shall be reported to management and such deviations shall be corrected in a timely manner.

4. Financial Reporting.

Holding and all subsidiaries shall prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial information shall be accumulated and prepared in accordance with Generally Accepted Accounting Principles. In addition, the accounting information prepared and maintained by LG&E shall conform to the requirements of the Public Service Commission of Kentucky and the Federal Energy Regulatory Commission's uniform system of accounts.

All intercompany transactions shall be reported and the nature and terms of the transactions should be fully described and explained.

Holding will file consolidated Federal and State income tax returns which will include LG&E's and any other subsidiaries' taxable income. The "stand alone" method will be used to allocate the income tax liabilities of each entity. Payment transfers for tax liabilities or tax benefits will be made on the dates established for the payment of Federal estimated income taxes.

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KU/KU Energy

Corporate Policies and Guidelines for Intercompany Transactions

CORPORATE POLICIES AND GUIDELINES FOR INTERCOMPANY TRANSACTIONS

PURPOSE

The purpose of this statement is to establish Policies and Guidelines to govern transactions between Kentucky Utilities Company ("KU"), its proposed Holding Company ("Holding") and any other non-utility subsidiary of Holding that may be created. The guidelines have been established to ensure that the following policies are adhered to with respect to inter-party transactions:

I. A distinct separation of costs between utility and non-utility activities will be maintained.

II. Intercompany transactions will be structured, and reimbursement made, in such manner that such transactions do not have an adverse impact on utility customers.

III. Strict internal controls will be maintained with respect to inter-party transactions to ensure that these polices are observed and to provide for adequate and effective regulatory oversight of KU's electric utility operations.

IV. All books and records of KU and all affiliates will be maintained in accordance with Generally Accepted Accounting Principles and, in addition, the books and records of KU will continue to comply with the requirements of the Uniform System of Accounts.

GUIDELINES

I. A distinct separation of costs between utility and non-utility activities will be maintained.

In order to achieve the maximum level of efficiency it is anticipated that there will be sharing of corporate resources. In those instances the costs of such resources will be allocated to the party receiving the benefit.

II. Intercompany transactions will be structured, and reimbursement made, in such manner that such transactions do not have an adverse impact on utility customers.

Prompt and fair reimbursement will be made with respect to any sale or transfer of assets, liabilities, or services between the parties. Separate accountability of management and records will be maintained to assure that transactions involving non-utility activities will not have an adverse impact on the utility or its customers.

Sales or transfer of assets are to be settled by cost or fair market value, whichever is greater when transfers or sales are made by KU to Holding, or other parties, and such transfers or sales are to be settled by cost or fair market value, whichever is lower when transfers are made to KU from Holding or other parties. Settlement or transfer of liabilities are to be treated in the same manner. These guidelines will insure that the utility will not be negatively impacted by an inter-party transaction.

Sales or provisions of services fall into two broad categories; continuing services (such as payroll) and special or periodic services (such as sale of common stock). For continuing services KU already has in place a responsibility accounting system, which will be used as the basis for cost allocation. For each responsibility area, which provides continuing services, an objective measure of the services provided (i.e., number of employees) will be determined and used to allocate the costs of that responsibility to Holding or any other subsidiary based on that measure.

The special or periodic services will be assigned a project number for each project, all direct costs accumulated and, with assignment of proper overheads, billed to Holding or any other subsidiary as appropriate.

The foregoing cost allocation methods will be reviewed at least annually and modifications made to reflect current operating conditions to ensure that all costs incurred for each party are assigned to that party.

Inter-party billings shall be issued on a timely basis with sufficient detail attached to assure an adequate audit trail and to provide for adequate and effective regulatory review. Payment shall be due upon receipt and past due 30 days after receipt of invoice. Late charges will be assessed by the billing company on past due amounts.

III. <u>Strict internal controls will be maintained with respect to inter-party transactions to ensure that these policies are observed and to provide for adequate and effective regulatory oversight of KU's electric utility operations</u>.

These policies and guidelines will be adopted by KU, by Holding and by each other subsidiary of Holding. Intercompany transactions will be documented in a consistent manner and in sufficient detail to develop an adequate audit trail. Intercompany transactions will be periodically audited and reports given to management as to compliance with these policies and guidelines.

Internal controls will be designed to ensure proper accountability by (1) recognizing all intercompany transactions, (2) establishing appropriate value, and (3) recording each transaction properly.

IV. <u>All books and records of KU and all affiliates will be maintained in accordance with Generally Accepted Accounting Principles and, in addition, the books and records of KU will continue to comply with the requirements of the Uniform System of Accounts</u>.

Holding and all subsidiaries are expected to provide timely financial information necessary to compile the required financial statements and to comply with other reporting requirements. All books and records will be maintained in accordance with Generally Accepted Accounting Principles and, in addition, the books and records of KU must meet the requirements of the Uniform System of Accounts. Audited financial statements are to be accompanied by notes summarizing significant accounting policies and other required disclosures.

It is anticipated that KU and Holding will file consolidated Federal and State income tax returns. Holding will receive and disburse payments between parties, which result from the "stand alone" method of computing income tax liabilities. The payment transfers will include quarterly installment responsibilities.

<u>MODIFICATION</u>

These guidelines will be modified from time to time as experience may require to ensure that the costs of all inter-company transactions are properly allocated, recorded and reimbursed.

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LG&E/KU

Corporate Policies and Guidelines for Intercompany Transactions

Corporate Policies and Guidelines
for Intercompany Transactions

These Policies and Guidelines have been established to set forth business practices to be observed in transactions between Louisville Gas and Electric Company ("LG&E"), Kentucky Utilities Company ("KU"), their Holding Company, LG&E Energy Corp. ("LG&E Energy") and any non-utility subsidiary created by LG&E Energy. As nonutility subsidiaries are created by LG&E Energy, these policies and guidelines will be revised and expanded to ensure that the non-regulated activities are not subsidized by LG&E's or KU's ratepayers. Updated policies and guidelines will be filed with the Public Service Commission on an annual basis.

Policies and Guidelines

1. Separation of costs between utility and non-utility activities will be maintained.

Distinct and separate accounting and financial records will be maintained and fully documented for each entity. All costs, which can be specifically identified and associated with an activity, will be directly assigned to that activity. Indirect costs, which provide a benefit to more than one activity, will be allocated to the activities that receive a benefit.

Although initially there will be a sharing of resources between LG&E, KU and LG&E Energy, to the extent practicable, each subsidiary of LG&E Energy will acquire and maintain its own facilities, equipment, staff and financing.

2. <u>Intercompany transactions shall be structured to ensure that non-regulated activities are not subsidized by the regulated utility</u>.

Separate accounting and financial records will be maintained to ensure that intercompany transactions related to non-utility activities will not have an adverse impact on the utilities or their customers.

Transfers or sales of assets will be priced at the greater of cost or fair market value for transfers or sales from LG&E or KU to LG&E Energy or other subsidiaries and at the lower of cost or fair market value for transfers or sales made to LG&E or KU from LG&E Energy or any of LG&E Energy's non-utility subsidiaries. Transfers or sales of assets between LG&E and KU will be priced at cost. Settlement or transfer of liabilities will be accounted for in the same manner. Through this policy, the utilities will receive the full benefit from intercompany transfers or sales.

LG&E or KU shall furnish a report to the PSC annually of each transfer of utility assets between themselves or between LG&E or KU and LG&E Energy or any of its non-utility subsidiaries, which has a value of $250,000 or more. Transfers having a value of less than $250,000 will be grouped and reported by specific categories, such as transportation equipment, power operated equipment, etc.

Transfers or sales of nonutility assets, payment of dividends and normal recurring transactions are expressly excluded from this reporting requirement.

All goods or services provided by LG&E or KU to LG&E Energy or any of its non-utility subsidiaries will be billed at cost, including the proper assignment of all indirect costs.

LG&E and KU will utilize their automated responsibility accounting system to accumulate and allocate costs among the various companies. To the extent possible, specific activities or projects will be directly recorded in the accounting and financial records of the appropriate company. Transactions affecting more than one entity will be allocated among the affected companies by reference to some reasonable, objective standard related to the facts and circumstances of the transaction (i.e., number of employees, number of transactions, etc.)

Billings for intercompany transactions shall be issued on a timely basis with documentation sufficient to provide for subsequent audit or regulatory review. Payments for intercompany transactions shall be made within thirty (30) days of receipt of the invoice. If payment is not made by the due date, late charges will be assessed by the billing company.

3. <u>Strict internal controls will be maintained to provide reasonable assurance that intercompany transactions are</u>

accounted for in accordance with management's policies and guidelines.

Accounting policies and procedures for intercompany transactions will be fully documented and provided to all entities. Intercompany transactions will be fully documented in sufficient detail to enable verification of the relevant information. Periodic audits will be made of intercompany transactions and transfer prices to ensure that these policies and guidelines are being observed. Any detected deviations from these policies and guidelines shall be reported to management and such deviations shall be corrected in a timely manner.

4. Financial Reporting.

LG&E Energy and all subsidiaries shall prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial information shall be accumulated and prepared in accordance with Generally Accepted Accounting Principles. In addition, the accounting information prepared and maintained by LG&E and KU shall conform to the requirements of the Public Service Commission of Kentucky and the Federal Energy Regulatory Commission's uniform system of accounts.

All intercompany transactions shall be reported and the nature and terms of the transactions should be fully described and explained.

LG&E Energy will file consolidated Federal and State income tax returns which will include LG&E's, KU's and any other subsidiaries' taxable income. The "stand alone" method will be used to allocate the income tax liabilities of each entity. Payment transfers for tax liabilities or tax benefits will be made on the dates established for the payment of Federal estimated income taxes.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF BASE RATES	))))	**CASE NO. 2008-00252**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	**CASE NO. 2007-00564**

REBUTTAL TESTIMONY

OF

WILLIAM E. AVERA

on behalf of

LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: December 19, 2008

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY OF WILLIAM E. AVERA

Table of Contents

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

CASE NO. 2008-00252

REBUTTAL TESTIMONY OF WILLIAM E. AVERA

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. ARE YOU THE SAME WILLIAM E. AVERA THAT PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS CASE?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to respond to the recommendations of Dr. J. Randall Woolridge, submitted on behalf of the Office of the Attorney General, and Mr. Lane Kollen, on behalf of Kentucky Industrial Utility Customers, Inc., concerning the return on equity ("ROE") for the utility operations of Louisville Gas and Electric Company ("LGE" or "the Company").

Q. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY.

A. Investors have many potential options for their funds, and LGE must compete for investment dollars. As documented in my rebuttal testimony, the cost of equity recommendations of Dr. Woolridge and Mr. Kollen are significantly downward-biased and out of touch with the requirements of real-world investors in the capital markets. The ROE recommendations of Dr. Woolridge and Mr. Kollen fail the most fundamental test of reasonableness because they do not provide LGE with the opportunity to earn returns that are comparable with those available from alternative investments of comparable risk. Considering investors' ongoing awareness of the risks associated with the utility industry specifically, and the implications of the ongoing financial crisis generally, supportive regulation remains crucial to maintaining LGE's access to capital.

II. THRESHOLD ISSUE

Q. DR. AVERA, IS IT POSSIBLE TO DISTILL THE MANY COMPLEXITIES ASSOCIATED WITH ESTIMATING INVESTORS' REQUIRED RATE OF RETURN INTO A SINGLE, THRESHOLD ISSUE?

A. Yes. While the details underlying a determination of the cost of equity are all significant to a rate of return analyst, there is one fundamental requirement that any ROE recommendation must satisfy before it can be considered reasonable. Competition for capital is intense, and utilities such as LGE must be granted the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments if they are to maintain their financial flexibility and ability to attract capital.

Rather than becoming bogged down in lengthy, academic arguments over the merits of one quantitative approach versus another, the Commission can make a determination on the key, threshold question: "Do the ROE recommendations of Dr. Woolridge and Mr. Kollen meet the threshold test of reasonableness required by established regulatory and economic standards governing a fair rate of return on equity?" Based on the evidence discussed subsequently, the answer is, "No."

Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING LGE'S ACCESS TO CAPITAL?

A. Considering investors' heightened awareness of the risks associated with the electric power industry and the implications of ongoing volatility in the markets for long-term capital, supportive regulation remains crucial in preserving LGE's access to capital. Capital markets recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. Moreover, considering the magnitude of the events that have recently occurred, investors' sensitivity to market and regulatory uncertainties has increased dramatically.

Q. IS IT WIDELY ACCEPTED THAT A UTILITY'S ABILITY TO ATTRACT CAPITAL MUST BE CONSIDERED IN ESTABLISHING A FAIR RATE OF RETURN?

A. Yes. This is a fundamental standard underlying the regulation of public utilities. The Supreme Court's landmark *Bluefield* and *Hope* decisions established that a regulated utility's authorized returns on capital must be sufficient to assure investors' confidence and that, if the utility is efficient and prudent on a prospective basis, it will have the opportunity to provide returns commensurate with those expected for other investments involving comparable risk. Dr. Woolridge also recognized that the opportunity to earn a return at least equal to those expected in the capital markets for comparable investments is a fundamental principle underlying the cost of equity.[1] This is absolutely correct. If LGE's return on equity does not fully reflect the level of investment risks that investors perceive, it will violate the risk-return tradeoff, breach applicable standards, and impair the Company's ability to attract necessary capital.

[1] Woolridge Direct at 19.

Q. WHAT BENCHMARKS ARE USEFUL IN EVALUATING THE EXTENT TO WHICH THE ROE RECOMMENDED BY DR. WOOLRIDGE MEETS THIS FUNDAMENTAL REGULATORY REQUIREMENT?

A. The comparable earnings standard recognizes that LGE must compete for capital with all firms in the capital markets generally, and against firms in its own industry specifically. The Value Line Investment Survey ("Value Line") reports that electric utilities as a whole are anticipated to earn a return of 11.5 percent in 2008 and 2009, and 13.0 percent over its 2011-2013 forecast horizon.[2] Meanwhile Value Line expects that natural gas utilities will earn an average rate of return on common equity of 11.0 percent to 12.0 percent.[3] A return that is significantly below the level that Value Line expects for utilities generally would undermine confidence in the financial integrity of the Company and its ability to attract capital.

Q. WHAT ARE THE POTENTIAL CONSEQUENCES OF AUTHORIZING A RATE OF RETURN LESS THAN WHAT IS REQUIRED TO MEET THE FINANCIAL END-RESULT TEST?

A. Considering the risks faced by LGE, the need to fund substantial investment in utility infrastructure, and the imperative of maintaining access to capital during times of adversity, setting an ROE that fails to provide investors with an opportunity to earn returns commensurate with companies of comparable risk would weaken LGE's financial integrity, violate the capital attraction standard, and send the wrong signal to investors at a time when access to capital markets is crucial for the Company.

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[2] The Value Line Investment Survey at 148 (Nov. 28, 2008).
[3] The Value Line Investment Survey at 446 (Dec. 12, 2008).

Q. WHAT IS THE PRIMARY REASON THAT DR. WOOLRIDGE FAILS TO REACH ROE RECOMMENDATIONS THAT WOULD GIVE LGE AN OPPORTUNITY TO EARN RETURNS COMMENSURATE WITH COMPANIES OF COMPARABLE RISK?

A. The primary reason is that he fails to account for real world investors' expectations in his application of the discounted cash flow ("DCF") and Capital Asset Pricing Model ("CAPM") approaches. Because Dr. Woolridge's application of these models does not reflect investors' expectations, the resulting cost of equity estimates fail to provide for a return sufficient to attract investors' money.

Q. HOW DO THE METHODS USED BY DR. WOOLRIDGE FAIL TO ACCOUNT FOR INVESTORS' EXPECTATIONS IN APPLYING THE DCF MODEL?

A. As will be documented below, investors rely on projections of professional financial analysts in forming expectations of the earnings growth for individual stocks. These professional financial analysts consider the historical record of growth in earnings, dividends, and book value as well as trends in relevant financial parameters such as dividend payouts, profitability, sales, technology, and economic growth in formulating their growth projections. While Dr. Woolridge considered these growth projections, he dilutes them with considerations of past historical growth rates and his own personal judgments. The flaw in attempting to meld these values and subjective arguments with the growth projections of professional securities analysts is that the financial analysts' growth projections already take into account each company's historical financial performance, current prospects, and the effects of macroeconomic factors.

Q. IS IT REASONABLE TO DISCOUNT THE PROJECTIONS OF FINANCIAL ANALYSTS AS "ROSY" OR "HIGHLY UNREALISTIC" AS DR. WOOLRIDGE CLAIMS?

A. No. My DCF analysis referenced alternative sources of analysts' growth rates from well-recognized investment publications. These estimates included consensus growth rates based on the projections of multiple analysts, considered projections of buy- and sell-side analysts as well as other investment professionals, and reflected independent estimates from firms with no investment banking or other market operations.

As will be discussed in detail below, there is ample evidence that contradicts the specific claims made by Dr. Woolridge. But his claims are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, it would be irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors' find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications implies that investors use them as a basis for their expectations.

Q. HOW DOES THE CAPM METHOD, AS APPLIED BY DR. WOOLRIDGE, FAIL TO CAPTURE INVESTORS' EXPECTATIONS?

A. Dr. Woolridge argues that forward-looking estimates of the spread between bond returns and stock returns, such as that incorporated in my CAPM analysis, are not a reliable basis for investors' expectations because some studies of historical data and his own personal beliefs suggest lower returns. The key question is not what investors should expect if they agreed with certain academic studies, selected surveys, or Dr.

Woolridge. It is rather, "What do investors expect given the inputs that today's investors would use in valuing the stocks?" Just as financial analysts' projections of future earnings growth have met the test of the market as a basis of investors' expectations for the growth of individual companies, so also have investors' expectations of the future spread between stock and bond returns. My forward-looking application of the CAPM uses a risk premium that is slightly higher than the historical risk premium as measured by arithmetic averages. This objective evidence suggests that investors do not share the opinions of Dr. Woolridge that the historical risk premium should be adjusted downward to reflect what investors "should" expect in future returns.

III. CHANGES IN CAPITAL MARKET CONDITIONS

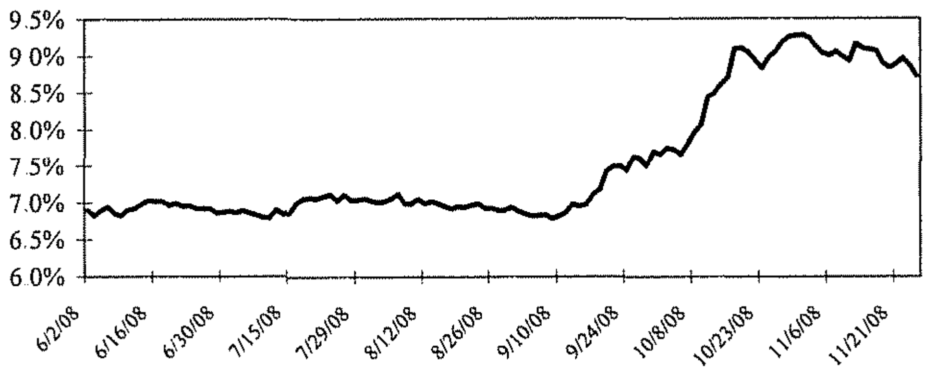
Q. WHAT ARE THE IMPLICATIONS OF RECENT CAPITAL MARKET CONDITIONS?

A. Recent volatility in the debt and equity markets linked to the ongoing financial crisis and the weakening economy evidences investors' trepidation to commit capital and marks a significant upward revision in their perceptions of risk and required returns. Bloomberg reported that the CBOE Volatility Index, commonly know as the VIX, recently surged 26 percent to almost triple its average during the past year, indicating unprecedented price fluctuations and uncertainty.[4] With respect to utilities specifically, as of November 30, 2008, the Dow Jones Utility Average stock index has declined over 26 percent since June 2008, while yields on utility bonds have increased precipitously. Figure WEA-1 below plots the yields on triple-B utility bonds reported

[4] Kearns, Jeff, "VIX 'Exploding' as Stocks Plunge on Growing Recession Concern," *Bloomberg* (Oct. 15, 2008).

by Moody's Investors Service ("Moody's") from June 2008 through November 30, 2008:

FIGURE WEA-1
MOODY'S TRIPLE-B PUBLIC UTILITY BOND YIELDS



At the time my direct testimony was prepared, the average yield on triple-B rated utility bonds was 6.8 percent. Meanwhile, Moody's reported that for the month of November 2008, the average yield on triple-B utility bonds had climbed to approximately 9.0 percent.

Q. WHAT DOES THIS EVIDENCE INDICATE WITH RESPECT TO ESTABLISHING A FAIR ROE FOR LGE?

A. The recent sell-off in common stocks and sharp increase in utility bond yields are indicative of higher costs for long-term capital, and the ongoing credit crisis has spilled over into the utility industry. For example, utilities have been forced to draw on short-term credit lines to meet debt retirement obligations because of uncertainties regarding the availability of long-term capital.[5] As the *Edison Electric Institute* ("EEI") noted in a recent letter to congressional representatives, the financial crisis has serious implications for utilities and their customers:

[5] Riddell, Kelly, "Cash-Starved Companies Scrap Dividends, Tap Credit," Pittsburgh Post-Gazette (Oct. 2, 2008).

> In the wake of the continuing upheaval on Wall Street, capital markets are all but immobilized, and short-term borrowing costs to utilities have already increased substantially. If the financial crisis is not resolved quickly, financial pressures on utilities will intensify sharply, resulting in higher costs to our customers and, ultimately, could compromise service reliability.[6]

Similarly, an October 1, 2008, *Wall Street Journal* report confirmed that dislocations in credit markets were also impacting the utility sector:

> Disruptions in credit markets are jolting the capital-hungry utility sector, forcing companies to delay new borrowing or come up with different—often more costly—ways of raising cash.[7]

An October 2008 report on the implications of credit market upheaval for utilities noted that, while high-quality companies can still issue debt, "they now have to pay an unusually high risk premium over Treasuries."[8] Meanwhile, a Managing Director with Fitch Ratings, Ltd. ("Fitch") recently observed that with debt costs at present levels, "significantly higher regulated returns will be required to attract equity capital."[9] As Fitch concluded:

> The collapse in secondary market debt pricing and in equity valuations is worrisome. We see new debt now priced at around 9% or higher pushing up against average authorized ROEs for utilities of around 10.25% to 10.50%. Thus, raising new equity, which is now priced close to book value, is likely to be dilutive.[10]

Q. DO YOU AGREE WITH DR. WOOLRIDGE THAT HIS RECOMMENDATION "IS CONSISTENT WITH THE CURRENT ECONOMIC ENVIRONMENT?"

A. No. Dr. Woolridge's assertion is patently false. While Dr. Woolridge touched on conditions in the capital markets and granted that "stocks reached a five-year high in

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6 *Letter to House of Representatives*, Thomas R. Kuhn, President, Edison Electric Institute (Sep. 24, 2008).
7 *Wall Street Journal* "Turmoil in Credit Markets Send Jolt to Utility Sector" (Oct. 1, 2008), p. B4.
8 *Rudden's Energy Strategy Report* (Oct. 1, 2008).
9 Fitch Ratings Ltd., "EEI 2008 Wrap-Up: Cost of Capital Rising," *Global Power North America Special Report* (Nov. 17, 2008).
10 Fitch Ratings Ltd., "Investing In An Unpredictable World," *Fitch Ratings' 20th Annual Global Power Breakfast* (Nov. 10, 2008).

terms of relative volatility,"[11] he diminished the importance of the recent financial crisis and his evaluation entirely fails to consider the implications of the resulting economic threats. For example, Dr. Woolridge observes (p. 2) that utilities and their investors face "volatile capital market conditions", but nevertheless grants (p. 3) that in making his recommendations, "certain financial data have not been updated to reflect the current economic situation." Rather than account for the economic realities facing today's investors, he simply asserts that "current market conditions are in disequilibrium as investors attempt to sort out the economic consequences of the collapse of the financial sector."[12] As a result, he recommends ignoring it altogether. In complete defiance of the investment community and in contrast to every observable financial benchmark, Dr. Woolridge miraculously concludes that "[l]ong-term capital costs for U.S. corporations are currently at their lowest levels in more than four decades."[13] Of course, as even a lay observer of capital markets would recognize, nothing could be further from the truth.

Q. DO THE CAPITAL MARKET BENCHMARKS CITED BY DR. WOOLRIDGE ACCURATELY REFLECT THE CURRENT EXPECTATIONS AND REQUIREMENTS OF LGE'S EQUITY INVESTORS?

A. No. Consistent with his admission that "certain financial data have not been updated to reflect the current economic situation," Dr. Woolridge restricted his evaluation to trends in government bond yields and other market data as of year-end 2007. As support for his inaccurate claim that corporate capital costs are at "historical low

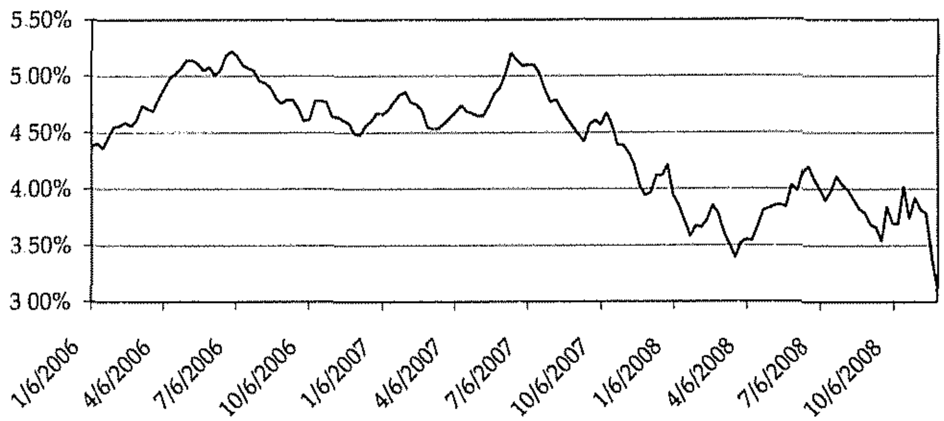
[11] Woolridge Direct at 56.
[12] Woolridge Direct at 3.
[13] Woolridge Direct at 6.

levels,"[14] Dr. Woolridge points to his observation that yields on 10-year Treasury bonds "have been in the 4-5 percent range for several years."[15] Dr. Woolridge's statement, as well as the inference he draws from it, are both incorrect.

Q. WHY IS DR. WOOLRIDGE'S OBSERVATION INCORRECT AND MISLEADING?

a. First, Dr. Woolridge's characterization of trends in 10-year Treasury bond yields is not accurate. Figure WEA-2, below, plots the weekly yields on 10-year Treasury bonds from 2006 through the end of November 2008:

FIGURE WEA-2
10-YEAR TREASURY BOND YIELDS



As shown above, beginning in the third quarter of 2007, the yields on 10-year Treasury bonds began a general decline and fell outside Dr. Woolridge's 4-5 percent band in early 2008. Despite the fact that he failed to recognize the implications of current financial data, Dr. Woolridge granted that:

> In 2008 Treasury yields have been pushed even lower as a result of the mortgage and sub-prime market credit crisis, the turmoil in the financial sector, the

[14] Woolridge Direct at 4.
[15] Woolridge Direct at 4, 6.

> prospect of an economic recession, and the government bailout of financial institutions.[16]

In response to accelerating concerns over economic uncertainties and the Federal Reserve's actions to increase liquidity in the face of a profound crisis in credit markets, the fall in Treasury bond yields has become increasingly pronounced, with the yield on 10-year notes falling below 3 percent in December 2008.

More importantly, however, in the current capital market climate trends in this interest rate benchmark have virtually no relevance in evaluating long-term capital costs for LGE. As a result of the turmoil and uncertainty spreading through financial markets, investors have sought a safe haven in government-backed securities, such as Treasury bonds. As a result, while the required returns for other asset classes, such as common stocks and public utility bonds, have moved sharply higher to compensate for increased perceptions of risk, the yields on Treasury securities have fallen significantly. In turn, the spread between the observable yields on corporate bonds and Treasury securities has spiked dramatically. As Standard & Poor's recently observed:

> The Standard & Poor's composite spreads widened to new five-year highs yesterday, leaving the investment-grade spread at 554 basis points (bps) and the speculative grade spread at 1,598 bps, both well more than triple their five-year moving averages. ... With speculative-grade defaults on the rise, a higher preponderance of credit downgrades, and a general malaise about the future of the economy, we expect spreads to remain at their elevated levels for some time until confidence is restored to the market.[17]

Dr. Woolridge's assessment of trends in public utility bond yields is similarly incomplete and misleading. In support of his contention that capital costs are at all-time lows, Dr. Woolridge presents a comparison of single-A public utility bond yields

[16] Woolridge Direct at 37.

[17] Standard & Poor's Corporation, "Credit Trends: U.S. Composite Credit Spreads Daily (Dec. 2, 2008)," *RatingsDirect* (Dec. 2, 2008).

through 2007 (Exhibit JRW-4, p. 1), concluding that yields "retreated to the 5.50% range by the end of 2007."[18] As documented above, however, Dr. Woolridge's conclusion is directly at odds with the capital market realities faced by investors. Yields on single-A utility bonds averaged 7.6 percent during November 2008,[19] or more than 200 basis points higher than those considered in Dr. Woolridge's testimony. In contrast to the conclusions of Dr. Woolridge, this implies a significant increase in the long-term capital costs for utilities, including LGE.

Dr. Woolridge performs the same flawed assessment in examining trends in public utility dividend yields. After evaluating historical dividend yields for the stocks included in the Dow Jones Utility Average, Dr. Woolridge concluded that they "have gradually declined over the past decade" and pointed to a year-end 2007 benchmark of 3.35 percent. Yet again, Dr. Woolridge completely ignores the realities in current capital markets. As indicated above, the prices of utility stocks have declined precipitously, which has pushed dividend yields significantly higher. Dow Jones & Company recently reported a current yield on its benchmark utility index of 4.29 percent, or 94 basis points above Dr. Woolridge's reference point. Confirming other capital market trends, this evidence supports a finding that the cost of long-term capital for LGE has increased significantly.

Q. DO YOU AGREE WITH DR. WOOLRIDGE (P. 4) THAT CHANGES IN DIVIDEND TAXATION ENACTED IN 2003 HAVE LED TO A SIGNIFICANT DECLINE IN INVESTORS' REQUIRED RATE OF RETURN ON EQUITY?

[18] Woolridge Direct at 18.

[19] Moody's Investors Service, www.credittrends.com (retrieved Dec. 4, 2008).

A. No. In light of the unprecedented capital market events of this year and the uncertainties associated with the incoming administration's policy responses, it is curious that Dr. Woolridge would choose to focus on 2003 tax legislation as support for his recommendations.[20] While dividend taxation is certainly one factor that may be considered by investors, the impact of changes in dividend taxation on the cost of equity for LGE is unclear. First, the important role that pension funds and tax deferred accounts play in the capital markets dilutes any effect that tax rate changes might have on investors' required rate of return. This is because the reduction in the taxation of dividends has no impact on the returns for tax-free investors.

Moreover, using current capital market data to estimate the cost of equity, such as my DCF and forward-looking CAPM approaches, already incorporates any effects of changes in tax policies. While Dr. Woolridge implies that changes in dividend taxation suggest a lower cost of equity than in the past, this ignores other significant factors that influence required returns. In particular, risk perceptions in general, and for electric utilities specifically, have shifted sharply upward, which would more than offset any decline in the equity risk premium due to changes in dividend taxation. Finally, investors are forward-looking and recognize that the reduction in dividend taxation is scheduled to expire in 2010. Given the mounting federal deficits, prospects for renewal are uncertain at best.

Q. DOES IT MAKE SENSE TO IGNORE CURRENT CAPITAL MARKET CONDITIONS, AS DR. WOOLRIDGE RECOMMENDS?

A. Absolutely not. As Dr. Woolridge correctly observed:

[20] The reduction in dividend taxation in the Jobs and Growth Tax Relief and Reconciliation Act of 2003 will expire at the end of 2010 unless renewed by Congress.

> The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates.[21]

But rather than consider this fundamental principle and the implications of current capital market trends, Dr. Woolridge completely disregarded the demonstrable increase in long-term capital costs. In contrast to Dr. Woolridge, the investment community is far less sanguine and there is very little indication that the dire conditions confronting the economy and financial markets will be resolved quickly. As a Managing Director for Fitch recently concluded, "I do not believe that borrowing costs will come down from current levels."[22] Even Dr. Woolridge begrudgingly adopted the upper end of his ROE range "in recognition of the volatile capital market conditions."[23]

As noted earlier, the standards underlying a fair rate of return require that LGE's authorized ROE reflect a return competitive with other investments of comparable risk and preserve the Company's ability to maintain access to capital on reasonable terms. This standard can only be met by considering the requirements of investors in today's capital markets. Past trends in interest rates or Dr. Woolridge's vague sense that conditions "are in disequilibrium" are irrelevant.

Similarly, contrary to Dr. Woolridge's contention, the fact that market volatility may complicate the application of quantitative methods to estimate the cost of equity provides no basis to ignore the dramatic upward shift in investors' risk perceptions and required rates of return for long-term capital. While markets may well be in "disequilibrium," as Dr. Woolridge asserts, this is nothing new. Capital

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[21] Woolridge Direct at 18-19.
[22] Grabelsky, Glen, "Surviving the Present, Preparing for the Future," *Fitch Ratings' 20th Annual Global Power Breakfast* (Nov. 10, 2008).
[23] Woolridge Direct at 2.

markets are continuously responding to current information and investors are incessantly revising their forward-looking expectations accordingly. It is for this very reason that it becomes even more critical to focus on current expectations, rather than backward-looking data, in estimating investors' required return during times of change, such as those confronting today's capital markets. Moreover, any "disequilibrium" in capital markets does not alter the simple fact that observable yields on long-term utility bonds have increased over 200 basis points above the benchmark levels that Dr. Woolridge cites in his testimony. This evidence alone demonstrates that LGE's ROE must be set far above the level recommended by Dr. Woolridge if the Supreme Court's standards underlying a fair rate of return are to be met in today's economic environment.

Since the 1930s, there has not been a time when the domestic and global financial markets have experienced as much turmoil and uncertainty as they are now undergoing. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse capital market conditions. The investment risks faced by utilities and their investors have only been exacerbated in this uncertain environment. In turn, the need for supportive regulation and an adequate ROE may never have been greater.

Q. WHAT ARE THE IMPLICATIONS OF DISREGARDING ACTUAL CAPITAL MARKET CONDITIONS IN SETTING THE ALLOWED RATE OF RETURN ON EQUITY?

A. If the increase in investors' required rate of return on long-term capital is not incorporated in the allowed rate of return on equity, the results will fail to meet the comparable earnings standard that is fundamental in determining the cost of capital. From a more practical perspective, failing to provide investors with the opportunity to earn a rate of return commensurate with LGE's risks will only serve to further weaken its financial integrity, while hampering the Company's ability to attract the capital needed to meet the economic and reliability needs of its service area.

Q. DOES THE IMPORTANCE OF AN ADEQUATE RETURN TO ATTRACT INVESTORS' CAPITAL DIMINISH IF THE UTILITY IS NOT PLANNING TO ISSUE NEW EQUITY?

A. Not at all. First, it is not always within the utility's control when it will have to access equity markets. Due to its obligation to serve, a utility may have to invest new capital even during adverse market conditions and its ability to withstand such periods of stress depends to a large degree on investors' confidence in supportive regulation, including an adequate ROE.

In the current crisis there has been much discussion of the problems created for homeowners who were induced into buying too much house by "teaser" interest rates that were very low at the outset, but then reset to higher rates after the first few years of the mortgage. Many problems could have been avoided if, at the outset, homeowners and lenders had looked beyond the low initial payments and focused on the long-term costs and implications of their mortgage terms. The long-term perspective is similarly important for regulators. The cost to customers in the long-term may be much higher if the allowed return in the near term limits the financial resiliency of the utility and renders it unable to raise capital on reasonable terms to fund crucial infrastructure investments, especially in times of financial stress.

If regulators opportunistically approve inadequate returns when the utility seems to be financially sound, then investor confidence is lost. As the western energy crisis of 2000-2001 demonstrated, it cannot be easily or quickly regained by simply granting higher returns in later years. It would be both unfair to LGE and against the long-term interest of customers to adopt a downward-biased ROE, such as those proposed by Dr. Woolridge and Mr. Kollen.

IV. J. RANDALL WOOLRIDGE

Q. WHAT ROE DID DR. WOOLRIDGE RECOMMEND FOR LGE?

A. Based on the results of his CAPM and DCF analyses, Dr. Woolridge developed an ROE range for LGE's electric utility operations of 8.2 percent to 9.9 percent,[24] and ultimately recommended a point estimate of 9.9 percent "in recognition of the volatile capital market conditions."[25] With respect to LGE's gas utility operations, Dr. Woolridge concluded that the cost of equity was in the 8.3 percent to 9.2 percent range; again selecting the 9,2 percent upper bound as his point estimate ROE recommendation. While Dr. Woolridge applied both the CAPM and risk premium methods, his recommendations effectively considered only the cost of equity produced by his applications of the constant growth DCF method.

A. Proxy Group

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S ASSERTIONS REGARDING THE ELIMINATION OF CERTAIN COMPANIES FROM HIS ELECTRIC PROXY GROUP IN ANALYZING THE COST OF EQUITY FOR LGE?

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[24] While Dr. Woolridge indicates on page 57 of his testimony that the range is 8.3 percent to 9.9 percent, this appears to be a typographical error, as the results of his analyses (p. 56) produce an 8.2 percent lower bound.
[25] Woolridge Direct at 2.

A. No. Dr. Woolridge argued for the elimination of companies if less that 75 percent of total revenues were attributable to electric utility operations.[26] However, he failed to demonstrate how this subjective criterion translates into differences in the investment risks perceived by investors. As I amply demonstrated in my direct testimony,[27] a comparison of objective indicators demonstrates that investment risks for the firms in my proxy groups are relatively homogeneous and comparable to LGE. Moreover, there are significant errors and inconsistencies associated with Dr. Woolridge's approach that justify rejecting his alternative proxy group altogether.

Q. DID DR. WOOLRIDGE DEMONSTRATE A NEXUS BETWEEN HIS SUBJECTIVE REVENUE CRITERION AND OBJECTIVE MEASURES OF INVESTMENT RISK?

A. No. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful proxy group to estimate investors' required return is relative risk, not the source of the revenue stream. Dr. Woolridge presented no evidence to demonstrate a connection between the subjective revenue criterion that he employed and the views of real-world investors in the capital markets.

Moreover, due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as total revenues, between utility segments (*e.g.*, electric and natural gas) or regulated and non-regulated sources. As a result, even if one were to ignore the fact that there is no clear link between the source of a utility's revenues and investors' risk perceptions, it is generally not possible to accurately and consistently apply revenue-

[26] Woolridge Direct at 9-10.
[27] Pages 23-25.

based criteria. In fact, other regulators have rebuffed these notions, with the Federal Energy Regulatory Commission ("FERC") rejecting attempts to restrict a proxy group to companies based on sources of revenues. As FERC recently concluded:

> This is inconsistent with Commission precedent in which we have rejected proposals to restrict proxy groups based on narrow company attributes.[28]

Indeed, as discussed below, reference to objective indicators of investment risk demonstrates that the investment risks of LGE are comparable to those of the firms that Dr. Woolridge argues to exclude based on his subjective assessment.

Q. WHAT OBJECTIVE EVIDENCE CAN BE EVALUATED TO CONFIRM THE CONCLUSION THAT HIS SUBJECTIVE REVENUE TEST IS NOT SYNONYMOUS WITH COMPARABLE RISK IN THE MINDS OF INVESTORS?

A. Bond ratings are perhaps the most objective guide to utilities' overall investment risks and they are widely cited in the investment community and referenced by investors. While the bond rating agencies are primarily focused on the risk of default associated with the firm's debt securities, bond ratings and the risks of common stock are closely related. As noted in *Regulatory Finance: Utilities' Cost of Capital*:

> Concrete evidence supporting the relationship between bond ratings and the quality of a security is abundant . . . . The strong association between bond ratings and equity risk premiums is well documented in a study by Brigham and Shome (1982).[29]

[28] *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 at P 118 (2008) (footnote omitted). Similarly, FERC has specifically rejected arguments analogous to those of Dr. Woolridge that utilities "should be excluded from the proxy group given the risk factors associated with its unregulated, non-utility business operations." *Bangor Hydro-Elec. Co.*, 117 FERC ¶ 61,129 at PP 19, 26 (2006).
[29] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utility Reports (1994) at 81.

Indeed, Dr. Woolridge also reviewed the bond ratings of the companies in his alternative proxy group.[30]

As I noted in my direct testimony (p. 38), LGE has been assigned a corporate credit rating of "BBB+" by S&P. Similarly, credit ratings assigned to my proxy utilities that were excluded by Dr. Woolridge based on his subjective test ranged from "BBB" to "A-", with the average credit rating of "BBB+" being identical to that of LGE. Considering that credit ratings provide one of the most widely referenced benchmarks for investment risks, a comparison of this objective risk indicator demonstrates that the range of risks for the companies eliminated under the subjective criterion proposed by Dr. Woolridge are entirely comparable to those of LGE.

Q. WHAT INCONSISTENCIES AND ERRORS ARE ASSOCIATED WITH THE REVENUE TEST PROPOSED BY DR. WOOLRIDGE?

A. First, while Dr. Woolridge screened all electric and combination electric and gas utilities followed by Value Line, his revenue test was based solely on <u>electric</u> revenues and ignored the impact of gas utility operations. For example, despite the fact that 100 percent of the operating revenues of PG&E Corporation are attributable to regulated electric and gas utility operations, Dr. Woolridge eliminated this firm from his proxy group. Similarly, Vectren Corporation reported in its 2007 Form 10-K Report that its regulated utility segment accounted for approximately 77 percent of total revenues, while Wisconsin Energy's utility segment posted 2007 revenues equal to 99.7 percent of the total consolidated revenues. Considering the similarities in the regulatory and business environments for electric and gas utility operations, his failure to incorporate gas utility revenues in implementing his test makes no sense.

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[30] Exhibit JRW-2.

Second, four of the six firms that Dr. Woolridge specifically cites in his testimony as being unsuitable comparables were never included in my proxy group in the first place. Specifically, Dr. Woolridge incorrectly states that Great Plains Energy, OGE Energy, Otter Tail Corporation, and Westar Energy were included in my proxy group and argues that these firms "are not appropriate".[31] But as a review of my Exhibit WEA-1 demonstrates, none of these firms are even included in my analyses.

Third, Dr. Woolridge's subjective assessment is inconsistent with the companies he accepted in his own reference group of utilities. For example, while Dr. Woolridge argued to exclude companies with substantial operations outside the electric utility sector, he included Hawaiian Electric Industries ("Hawaiian Electric") in his reference group. But in addition to its electric utility operations, Hawaiian Electric also owns and operates American Savings Bank, which is the third largest financial institution in Hawaii. Despite the fact that competitive banking activities accounted for approximately 41 percent of operating income in 2007, Dr. Woolridge elected to include Hawaiian Electric in his proxy group.

Finally, Dr. Woolridge's artificial revenue threshold for his electric utility group is inconsistent with his findings for the gas utilities included in his analyses. Dr. Woolridge observed that, on average, his gas utility group "receives 68% of revenues from regulated gas operations."[32] If Dr. Woolridge finds it acceptable for certain gas utilities to have less than 68 percent of revenues from gas utility operations, why then did he exclude comparably situated electric utilities? Alternatively, why did he not hold gas utilities to the same 75 percent revenue

[31] Woolridge Direct at 62.
[32] Woolridge Direct at 10.

threshold imposed on his electric utility group if this is a meaningful indicator of comparable risk? The answer, of course, is that Dr. Woolridge's revenue statistic has no demonstrable link to risk and his internal inconsistency merely highlights the entirely subjective and baseless nature of his "test".

Q. ARE THERE OTHER ERRORS ASSOCIATED WITH DR. WOOLRIDGE'S APPLICATION OF HIS ELECTRIC PROXY GROUP CRITERIA?

A. Yes. Three of the utilities included in Dr. Woolridge's proxy group violate his criteria, which included the requirement that they maintain an investment grade credit rating.[33] Specifically, Central Vermont Public Service Corporation ("Central Vermont"), PNM Resources, Inc. ("PNM"), and UniSource Energy Corporation ("UniSource") are all currently assigned speculative, or "junk" bond ratings. S&P noted in June 2005 that it lowered its corporate credit rating for Central Vermont Public Service from "BBB-" to "BB+", citing an adverse shift in the utility's regulatory environment.[34] Similarly, S&P lowered its credit rating on PNM to "BB+" in April 2008.[35] S&P does not report a credit rating for UniSource, but has assigned a "BB+" rating to its principal utility subsidiary, Tucson Electric Power Company.[36] While Moody's does not currently publish a credit rating for Central Vermont, it rates the company's preferred stock at "Ba2".[37] Moody's has assigned senior unsecured

[33] Woolridge Direct at 10.

[34] Standard & Poor's Corporation, "Research Update: Central Vermont Public Service Rating Lowered, Off Watch Neg," *RatingsDirect* (June 10, 2005).

[35] Standard & Poor's Corporation, "PNM Resources Rating Lowered to 'BB+', Placed On CreditWatch With Negative Implications," *RatingsDirect* (Apr. 18, 2008).

[36] Standard & Poor's Corporation, "Research Update: Tucson Electric Power Co. Corporate Credit Rating Raised to 'BB+'," *RatingsDirect* (Dec. 2, 2008)

[37] Moody's Investors Service, "Credit Opinion: Central Vermont Public Service Corp.," *Global Credit Research* (May 12, 2008).

credit ratings of "Ba2" and "Ba1" to PNM and UniSource, respectively.[38] Thus, both of these utilities fall below the bottom end of the investment grade scale and should have been eliminated from Dr. Woolridge's proxy group under his own screening criteria.

B. DCF Method

Q. WHAT ARE THE FUNDAMENTAL DIFFERENCES BETWEEN YOUR DCF ANALYSIS AND THAT OF DR. WOOLRIDGE?

A. There are four key distinctions between my DCF analysis and that of Dr. Woolridge: 1) whereas Dr. Woolridge incorporates historical results as being indicative of what investors expect, my analysis focuses directly on forward-looking data; 2) Dr. Woolridge discounts reliance on analysts' growth forecasts for earnings per share ("EPS") as somehow biased, while my application of the DCF model recognizes that it is investors' *perceptions and expectations* that must be considered in applying the DCF model; 3) rather than looking to the capital markets for guidance as to investors' forward-looking expectations, Dr. Woolridge applies the DCF model based on his own personal views; and, 4) whereas my analysis explicitly excludes data that results in illogical cost of equity estimates, Dr. Woolridge essentially assumes that any resulting bias will be eliminated through averaging.

Q. DO YOU BELIEVE THAT THE RESULTS OF DR. WOOLRIDGE'S DCF ANALYSIS MIRRORS INVESTORS' LONG-TERM EXPECTATIONS IN THE CAPITAL MARKETS?

[38] Moody's Investors Service, "Credit Opinion: PNM Resources, Inc.," *Global Credit Research* (May 27, 2008); Moody's Investors Service, "Issuer Comment: UniSource Energy Corporation," *Global Credit Research* (Mar. 7, 2008).

A. No. There is every indication that his DCF results are biased downward and fail to reflect investors' required rate of return. As I explained in my direct testimony, historical growth rates (such as those referenced by Dr. Woolridge to apply the DCF model) are colored by the structural changes and numerous challenges faced in the utility industry. Moreover, given recent financial trends in the utility industry and the importance of earnings in determining future cash flows and stock prices, growth rates in dividends per share ("DPS") and book value per share ("BVPS") are not likely to be indicative of investors' long-term expectations. As a result, DCF estimates based on these growth rates do not capture investors' required rate of return for the industry.

Consider Dr. Woolridge's reference to historical growth rates, for example. If past trends in EPS, DPS, and BVPS are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. As Dr. Woolridge concluded:

> [T]o best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.[39]

While past conditions for utilities serve to depress historical growth measures, they are not representative of long-term expectations for the electric utility industry. Moreover, to the extent historical trends for electric utilities are meaningful, they are also captured in projected growth rates, such as those published by Value Line, IBES, Reuters, and Zacks since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends.

[39] Woolridge Direct at 29.

Q. IS THE DOWNWARD BIAS INHERENT IN HISTORICAL GROWTH MEASURES FOR ELECTRIC UTILITIES EVIDENT IN DR. WOOLRIDGE'S DCF ANALYSES?

A. Yes, it is. For example, consider the historical growth measures displayed on page 3 of Dr. Woolridge's Exhibit JRW-6. As shown there, the average 5-year historical growth rates for the utilities in Dr. Woolridge's proxy group ranged from zero to 4.0 percent. Over two-thirds of the individual historical growth rates reported by Dr. Woolridge for the companies in his electric proxy group were 3.0 percent or less, with many being zero or negative. Similarly, one-third of the historical growth rates for Dr. Woolridge's gas proxy group were 3.0 percent or less. Combining a growth rate of 3.0 percent with Dr. Woolridge's dividend yield of 4.3 percent implies a DCF cost of equity of approximately 7.4 percent. This implied cost of equity falls below the average yield on single-A public utility bonds reported by Moody's for November 2008 of approximately 7.6 percent. Clearly, the risks associated with an investment in public utility common stocks exceeds those of long-term bonds, and Dr. Woolridge's historical growth measures result in a built-in downward bias to his DCF conclusions, which provide no meaningful information regarding the expectations and requirements of investors.

Q. DID DR. WOOLRIDGE ALSO INCLUDE PROJECTED GROWTH RATES THAT RESULT IN ILLOGICAL DCF COST OF EQUITY ESTIMATES?

A. Yes. For example, four of the projected DPS growth rates included in Dr. Woolridge's DCF analysis for his electric utility group are equal to zero,[40] which

[40] Woolridge Direct at Exhibit JRW-6, p. 4. While growth rates equal to zero illustrate the downward bias inherent in Dr. Woolridge's analyses, many of the other growth estimates are too low to be considered credible.

implies an indicated cost of equity equal to the utility's dividend yield. Similarly, four of the ten projected DPS growth rates for Dr. Woolridge's gas utility group ranged from zero to 2.5 percent,[41] implying a cost of equity of at most 6.1 percent. Even though these results are clearly illogical, Dr. Woolridge included these growth rates in developing his conclusions using the DCF model.

Q. DID DR. WOOLRIDGE MAKE ANY EFFORT TO TEST THE REASONABLENESS OF THE INDIVIDUAL GROWTH ESTIMATES HE RELIED ON TO APPLY THE CONSTANT GROWTH DCF MODEL?

A. No. Dr. Woolridge simply calculated the average and median of the individual growth rates with no consideration for the reasonableness of the underlying data. In fact, many of the growth measures embodied in Dr. Woolridge's application of the constant growth DCF application make no economic sense.

For example, consider the projected growth rates from Bloomberg included in Dr. Woolridge's evaluation. As shown on page 5 of Exhibit JRW-6, the individual values for the firms in his electric proxy group ranged from 2.75 percent to 34.00 percent. Combining these growth rates referenced by Dr. Woolridge with his average dividend yield suggests a DCF cost of equity range of 7.1 percent to 39.0 percent using his methodology.[42] Clearly, DCF estimates that imply a cost of equity below the yield on public utility bonds or in excess of 30 percent violate economic logic and hardly represents an informed evaluation of investors' expectations. Moreover, reliance on the median value for a series of illogical values does not correct for the

[41] Woolridge Direct at Exhibit JRW-6, p. 4.
[42] Dr. Woolridge adjusted his dividend yield for one-half year's growth.

inability of individual cost of equity estimates to pass fundamental tests of economic logic.

Q. HAS DR. WOOLRIDGE RECOGNIZED THE IMPORTANCE OF EVALUATING MODEL INPUTS IN OTHER FORUMS?

A. Yes. Dr. Woolridge participated in the development of the *ValuePro* website, which is an online valuation service largely based on application of the DCF model.[43] *ValuePro* confirmed the importance of evaluating the reasonableness of inputs to the DCF model:

> Garbage in, Garbage out! Like any other computer program, if the inputs into our Online Valuation Service are garbage, the resulting valuation also will be garbage.[44]

Unlike his approach here, Dr. Woolridge advised investors to use common sense in interpreting the results of valuation models, such as the DCF:

> If a figure comes up for a certain input that is either highly implausible or looks wrong, indeed it may be. If a valuation is way out of line, figure out where the Service may have strayed on a valuation, and correct it.[45]

Given the fact that many of the growth rates relied on by Dr. Woolridge result in illogical cost of equity estimates, it is appropriate to take the same critical viewpoint when evaluating inputs to the DCF model in this proceeding.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S DECISION TO GIVE "GREATER WEIGHT" TO DCF RESULTS IN ESTABLISHING AN ROE FOR LGE?

A. No. Despite Dr. Woolridge's attempt to cast the CAPM in an unfavorable light, it is generally considered to be the most widely referenced method for estimating the cost

[43] www.valuepro.net.
[44] http://www.valuepro.net/abtonline/abtonline.shtml.
[45] *Id.*

of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. Considering the results of alternative methods and approaches provides greater confidence that the end result is reflective of investors' required rate of return. Investors' expectations are unobservable, and there is no methodology that provides a foolproof guide to their required rate of return. Each method provides another facet of examining investor behavior, with different assumptions and premises. Investors do not necessarily subscribe to any one method, and no model can conclusively determine or estimate the required return for an individual firm. If the cost of equity estimation is restricted to certain methodologies, while the results of other approaches are ignored, it may significantly bias the outcome. Rather, all relevant evidence should be weighed and evaluated in order to minimize the potential for error. *Regulatory Finance: Utilities' Cost of Capital* concluded that:

> When measuring equity costs, which essentially deal with the measurement of investor expectations, no one single methodology provides a foolproof panacea. If the cost of equity estimation process is limited to one methodology, such as DCF, it may severely bias the results.[46]

Regulators have customarily considered the results of alternative approaches in determining allowed returns.[47] It is widely recognized that no single method can be regarded as a panacea; all approaches have advantages and shortcomings. For example, a publication of the Society of Utility and Financial Analysts (formerly the National Society of Rate of Return Analysts), concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the

[46] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utilities Reports (1994) at 238.

[47] For example, a NARUC survey reported that 26 regulatory jurisdictions ascribe to no specific method for setting allowed ROEs, with the results of all approaches being considered. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996).

> proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[48]

As I explained in my direct testimony, the CAPM method is widely recognized as a meaningful approach to estimate investors' required rate of return. While there are significant flaws in Dr. Woolridge's application of the CAPM approach that results in a downward biased cost of equity estimate, there is no basis to favor the DCF model over other approaches if properly applied.

Q. PLEASE RESPOND TO DR. WOOLRIDGE'S CRITICISMS REGARDING RELIANCE ON EPS GROWTH PROJECTIONS IN APPLYING THE DCF MODEL.

A. In applying the DCF model to estimate the cost of equity, the <u>only</u> relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Dr. Woolridge's claim that analysts' estimates are not relied upon by investors is illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, it would be irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications implies that investors use them as a basis for their expectations.

[48] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at Part 2, p. 4.

The continued success of investment services such as IBES and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *Regulatory Finance: Utilities' Cost of Capital*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts also exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. ... Published studies in the academic literature demonstrate that growth forecasts made by securities analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth. ... Cragg and Malkiel (1982) presented detailed empirical evidence that the average analyst's expectation is more similar to expectations being reflected in the marketplace than are historical growth rates, and that they represent the best possible source of DCF growth rates.[49]

Q. DOES THE FACT THAT ANALYSTS' EPS PROJECTIONS MAY DEVIATE FROM ACTUAL RESULTS HAMPER THEIR USE IN APPLYING THE DCF MODEL, AS DR. WOOLRIDGE CONTENDS?

A. No. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the

[49] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utilities Reports, Inc. (1994) at 154-155.

expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. While I did not rely solely on EPS projections in applying the DCF model,[50] my evaluation clearly supports greater reliance on EPS growth rate projections than other alternatives. Moreover, there is every indication that expectations for earnings growth are instrumental in investors' evaluation and the fact that analysts' projections deviate from actual results provides no basis to ignore this relationship.

Q. DO THE SELECTED ARTICLES REFERENCED BY DR. WOOLRIDGE IN SUPPORT OF HIS CONTENTION THAT ANALYSTS ARE OVERLY OPTIMISTIC PAINT A COMPLETE PICTURE OF THE FINANCIAL RESEARCH IN THIS AREA?

A. No. In contrast to Dr. Woolridge's assertions, peer-reviewed empirical studies do not uniformly support his contention that analysts' growth projections are optimistically biased. For example, a study reported in "Analyst Forecasting Errors: Additional Evidence" found no optimistic bias in earnings projections for large firms (market capitalization of \$500-\$3,000 million), with data for the largest firms (market capitalization > \$3,000 million) demonstrating a *pessimistic* bias.[51] Similarly, a 2005 article that examined analyst growth forecasts over the period 1990 through 2001 illustrated that Wall Street's forecasting is not inherently optimistic:

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[50] As shown on Schedules WEA-1 and WEA-3, I also examined the "br+sv", sustainable growth rates for the companies in my proxy groups.

[51] Brown, Lawrence D., "Analyst Forecasting Errors: Additional Evidence," *Financial Analysts Journal* (November/December 1997).

> The pessimism associated with profit firms is astonishing. Near the end of the sample period, almost three quarters of the quarterly forecasts for profit firms are pessimistic.[52]

Other research on this topic also concludes that there is no clear support for the contention that analyst forecasts contain upside bias:

> Our examples do demonstrate how some widely held beliefs about analysts' proclivity to commit systematic errors (e.g., the common belief that analysts generally produce optimistic forecasts) are not well supported by a broader analysis of the distribution of forecast errors. After four decades of research on the rationality of analysts' forecasts it is somewhat disconcerting that the most definitive statements observers and critics of earnings forecasters are willing to agree on are ones for which there is only tenuous empirical support.[53]

More importantly, however, comparisons between forecasts of future growth expectations and the historical trend in actual earnings are largely irrelevant in evaluating the use of analysts' projections in the DCF model. For example, Dr. Woolridge references a paper he authored that reported that analysts' earnings growth rate estimates are overly optimistic, based on just such a historical comparison.[54] But as noted earlier, the investment community can only make decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and the fact that projections deviate from actual results says nothing about whether investors rely on analysts' estimates. In using the DCF model to estimate investors' required returns, the purpose is not to prejudge the accuracy or rationality of investors' growth expectations. Instead, to accurately estimate the cost of equity we must base our analyses on the growth expectations investors actually used in determining the price they are willing to pay for common stocks – even if we do not

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[52] Ciccone, Stephen, "Trends in analyst earnings forecast properties," *International Review of Financial Analysis*, 14:2-3 (2005).

[53] Abarbanell, Jeffery and Reuven Lehavy, "Biased forecasts or biased earnings? The role of reported earnings in explaining apparent bias and over/under reaction in analysts earnings forecasts," *Journal of Accounting and Economics*, 36: 142 (2003).

[54] Woolridge, Randall J. and Custatis, Patrick, "The Accuracy of Analysts' Long-Term Earnings Per Share Growth Rate Forecasts" (January 24, 2008).

agree with their assumptions. Indeed, despite the findings of his research, Dr. Woolridge reportedly "remains somewhat puzzled that so many continue to put great weight in what [analysts] have to say."[55] As Robert Harris and Felicia Marston noted in their article in *Journal of Applied Finance*:

> ...Analysts' optimism, if any, is not necessarily a problem for the analysis in this paper. If investors share analysts' views, our procedures will still yield unbiased estimates of required returns and risk premia.[56]

Similarly, there is no logical foundation for criticisms such as those raised by Dr. Woolridge that the purported upward bias of analysts' growth rates limits their usefulness in applying the DCF model. If investors' base their expectations on these growth rates, then they are useful in inferring investors' required returns – even if the analysts' forecasts prove to be wrong in hindsight.[57]

Q. IS THE $1.5 BILLION SETTLEMENT NEGOTIATED IN 2002 BY THE SECURITIES EXCHANGE COMMISSION AND THE NEW YORK ATTORNEY GENERAL OVER STOCK RESEARCH CONFLICTS RELEVANT TO THE PRESENT CASE?

A. No. Dr. Woolridge refers to this 6-year-old investigation in support of his decision to downplay analysts' growth rates in applying the DCF model. The Global Settlement of Conflicts of Interest Between Research and Investment Banking (Global Settlement) followed joint investigations by multiple regulators of allegations of undue influence of investment banking interests on securities research of sell-side

[55] Boselovic, Len, "Study Finds Analysts' Forecasts Have Been Too Sunny," *Pittsburgh Post-Gazette* (Mar. 30, 2008).
[56] Harris, Robert S. and Marston, Felicia C., "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," *Journal of Applied Finance* 11 (2001) at 8.
[57] I began my military career in the Navy in the weather office at a Naval Air Station. Using the best available methods then available, we provided pilots with weather forecasts for their flight plans. In hindsight we were not very accurate, but I do not recall any pilot ignoring our forecast in planning a mission. In finance, as in weather, no one knows the future. But no one can afford to ignore the best available forecasts.

analysts at brokerage firms.[58] In addition to monetary payments, the Global Settlement also required compliance with significant requirements that dramatically reformed their future practices. The firms were required to sever the links between research and investment banking, including prohibiting analysts from receiving compensation for investment banking activities, and prohibiting analysts' involvement in investment banking "pitches" and "roadshows." These important reforms included physically separating research and investment banking departments, eliminating any connections between research analysts' compensation and investment banking revenues, prohibiting research analysts from participating in efforts to solicit investment banking business, and creating and enforcing firewalls restricting interaction between investment banking and research. In addition, for a five-year period, each of the firms was required to contract with no fewer than three independent research firms to make independent research available to the firm's customers.

Of course, the analysts' growth projections referenced in my testimony were developed years after these measures were instituted. In contrast to Dr. Woolridge's assertions, the reforms resulting from this 2003 settlement support greater – not less – reliance on analysts' forecasts. At the conclusion of the settlement, the New York Attorney General concluded that "[t]he wide-ranging structural reforms to firms' research operations will empower investors to use securities research in a practical and meaningful way when making investment decisions."[59] Similarly, a recent study reported in *Financial Analysts' Journal* concluded that buy-side analysts actually

[58] The research in question did not pertain specifically to utilities; rather, it was largely related to allegations that stock prices were inflated by biased investment advice of affiliated brokerage firms in order to "spin" initial public offerings of stock.

[59] *Financial Industry Regulatory Authority*, News Release (Apr. 28, 2003).

made more optimistic and less accurate forecasts than their counterparts on the sell-side.[60]

Q DID DR. WOOLRIDGE PROVIDE ANY SUPPORT FOR HIS ALLEGATION (P. 73) THAT VALUE LINE FORECASTS ARE "UPWARDLY BIASED"?

A. No. Dr. Woolridge simply asserted his personal belief that Value Line projections have "a decidedly positive bias."[61] But Dr. Woolridge's personal opinions are irrelevant to a determination of what investors expect and, contrary to his conclusion, Value Line is a well-recognized source in the investment and regulatory communities. For example, *Cost of Capital – A Practitioners' Guide*, published by the Society of Utility and Financial Analysts, noted that:

> [A] number of studies have commented on the relative accuracy of various analysts' forecasts. Brown and Rozeff (1978) found that Value Line was superior to other forecasts. Chatfield, Hein and Moyer (1990, 438) found, further "Value Line to be more accurate than alternative forecasting methods" and that "investors place the greatest weight on the forecasts provided by Value Line".[62]

Given the fact that Value Line is perhaps the most widely available source of information on common stocks, the projections of Value Line analysts provide an important guide to investors' expectations. Moreover, in contrast to Dr. Woolridge's unsupported assertion, the fact that Value Line is not engaged in investment banking or other relationships with the companies that it follows reinforces its impartiality in the minds of investors. Indeed, Value Line was among the providers of "independent research" that benefited from the Global Settlement cited by Dr. Woolridge.[63]

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[60] Groysberg, Boris, Paul Healy, and Craig Chapman, "Buy-Side vs. Sell-Side Analysts' Earnings Forecasts," *Financial Analysts Journal* (July/August 2008).
[61] Woolridge Direct at 73.
[62] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at 8-28.
[63] Tsao, Amy, "The New Era of Indie Research," *Business Week Online Edition* (June 12, 2003).

Q. IS THERE A DOWNWARD BIAS INHERENT IN DR. WOOLRIDGE'S APPLICATION OF THE DCF MODEL BASED ON THE INTERNAL, "BR" GROWTH RATE?

A. Yes. Dr. Woolridge based his calculation of the internal, "br+sv" retention growth rate on data from Value Line, which reports end-of-period results. If the rate of return, or "r" component of the "br+sv" growth rate is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year. This downward bias, which has been recognized by regulators,[64] is illustrated in the table below.

Consider a hypothetical firm that begins the year with a net book value of common equity of $100. During the year the firm earns $15 and pays out $5 in dividends, with the ending net book value being $110. Using the year-end book value of $110 to calculate the rate of return produces an "r" of 13.6 percent. As the FERC has recognized, however, this year-end return "must be adjusted by the growth in common equity for the period to derive an average yearly return."[65] In the example below, this can be accomplished by using the average net book value over the year ($105) to compute the rate of return, which results in a value for "r" of 14.3 percent. Use of the average rate of return over the year is consistent with the theory of this approach to estimating investors' growth expectations, and as illustrated below, it can have a significant impact on the calculated retention growth rate:

[64] See, *e.g.*, *Southern California Edison Company,* Opinion No. 445 (Jul. 26, 2000), 92 FERC ¶ 61,070.
[65] *Id.*

Beginning Net Book Value	$100
Earnings	15
Dividends	5
Retained Earnings	10
Ending Net Book Value	$110

"b x r" Growth	End-of Year	Average
Earnings	$ 15	$ 15
Book Value	$110	$105
"r"	13.6%	14.3%
"b"	66.7%	66.7%
"b x r" Growth	**9.1%**	**9.5%**

Because Dr. Woolridge did not adjust to account for this reality in his analysis, the "internal" growth rates that he considered are downward-biased.

In addition, Dr. Woolridge completely ignored the "sv" component of the sustainable growth rate. Under DCF theory, the "sv" factor is a component designed to capture the impact on growth of issuing new common stock at a price above, or below, book value. As noted by Myron J. Gordon in his 1974 study:

> When a new issue is sold at a price per share P = E, the equity of the new shareholders in the firm is equal to the funds they contribute, and the equity of the existing shareholders is not changed. However, if P > E, part of the funds raised accrues to the existing shareholders. Specifically...[v] is the fraction of the funds raised by the sale of stock that increases the book value of the existing shareholders' common equity. Also, "v" is the fraction of earnings and dividends generated by the new funds that accrues to the existing shareholders.[66]

In other words, the "sv" factor recognizes that when new stock is sold at a price above (below) book value, existing shareholders experience equity accretion (dilution). In the case of equity accretion, the increment of proceeds above book value (P > E in Professor Gordon's example) leads to higher growth because it increases the book value of the existing shareholders' equity. In short, the "sv" component is entirely consistent with DCF theory, and the fact that Dr. Woolridge's analysis failed to

[66] Gordon, Myron J., "The Cost of Capital to a Public Utility," MSU Public Utilities Studies (1974), at 31–32.

consider the incremental impact on growth results in another downward bias to his "internal" growth rates.

Q. HOW DO THE CURRENT DIVIDEND YIELDS FOR DR. WOOLRIDGE'S ELECTRIC AND GAS PROXY GROUPS COMPARE WITH THE VALUES USED IN HIS DCF ANALYSES?

A. Utility stock prices have continued to decline sharply in response to the upward revision in investors' required returns. As a result, dividend yields have also increased significantly. As shown on Schedule WEA-9, based on average closing prices in November 2008, the expected dividend yield for Dr. Woolridge's electric proxy group is now approximately 5.2 percent, versus the 4.4 percent calculated in his direct testimony. Similarly, the dividend yield for the firms in Dr. Woolridge's gas proxy group has also increased and is approximately 30 basis points higher than the adjusted figure used in his testimony.

Q. WHAT COST OF EQUITY IS INDICATED IF THIS CURRENT DIVIDEND YIELD IS INCORPORATED INTO DR. WOOLRIDGE'S DCF ANALYSIS FOR HIS ELECTRIC PROXY GROUP?

A. Combining Dr. Woolridge's 5.5 percent growth rate with the 5.2 percent dividend yield for his electric proxy group based on average closing stock prices in November 2008 results in an indicated cost of equity of 10.7 percent. Because this estimate relies on Dr. Woolridge's growth rate, which incorporates the impact of the understatements and illogical values discussed earlier, this result continues to be downward biased. Nevertheless, it confirms my conclusion that a fair ROE for LGE should be established well above Dr. Woolridge's range.

Q. DOES DR. WOOLRIDGE RAISE ANY MEANINGFUL CRITICISMS REGARDING YOUR DCF ANALYSIS FOR YOUR NON-UTILITY PROXY GROUP?

A. No. Dr. Woolridge simply repeats his earlier complaint that the analysts' growth estimates I used to apply the DCF model are somehow upward biased. The fallacy of this argument was addressed at length earlier. In addition, Dr. Woolridge observed that my Non-Utility Proxy Group "includes such companies as Coca-Cola, General Electric, IBM, Johnson & Johnson, McDonalds, Microsoft, and NIKE," and concluded these companies are "vastly different" from utilities and do not operate in a "highly regulated environment."[67] In fact, however, the simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return. For example, consider (1) an electric utility operating in regulated markets that has experienced an inability to recover the costs incurred to provide service, and (2) Wal-Mart Stores, Inc. ("Wal-Mart"), which faces competition on numerous fronts. Despite its lack of a regulated monopoly, with a double-A bond rating, the highest Value Line Safety Rank, and a beta of 0.70, the investment community would undoubtedly regard Wal-Mart as the less risky alternative. In fact, my review of objective indicators of investment risk – which consider the impact of competition and market share – demonstrated that, if anything, the Non-Utility Proxy Group is <u>less</u> risky in the minds of investors than the common stock of electric utilities, including LGE.

Meanwhile, the implication that an estimate of the required return for firms in the competitive sector of the economy is not useful in determining the appropriate

[67] Woolridge Direct at 63.

return to be allowed for rate-setting purposes is wrong. In fact, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility.[68] Similarly, Dr. Woolridge recognized, "The perceived risk of a firm is the predominant factor that influences investor return requirements,"[69] and that allowed returns "should be commensurate with returns on other investments in other enterprises having comparable risks."[70] Dr. Woolridge's comparison of relative investment risks between electric utilities and other key industry groups supports the comparability of my non-utility proxy group. Dr. Woolridge noted (p. 19) that under modern capital market theory, beta is the only relevant measure of investment risk, with the average beta values for the electric utility industry groups reported by Value Line exceeding the average beta for my non-utility proxy group.[71]

C. CAPM Approach

Q. WHAT IS THE FUNDAMENTAL PROBLEM ASSOCIATED WITH DR. WOOLRIDGE'S APPROACH TO APPLYING THE CAPM?

A. Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflects the expectations of actual investors in the market. However, while Dr. Woolridge

[68] *Fed Power Comm'n v Hope Natural Gas Co* , 320 U.S. 591 (1944).
[69] Woolridge Direct at 19.
[70] Woolridge Direct at 20.
[71] Dr. Woolridge reported average betas of 0.93, 0.88, and 0.84 for the Value Line Central, West, and East utility groups, while my non-utility proxy group has an average beta of 0.79 (Table 2).

recognized that "ex post returns are not the same as ex ante expectations" and noted that "market risk premiums can change over time; increasing when investors become more risk-averse,"[72] his application of the CAPM method was based entirely on *historical* – not projected – rates of return. The primacy of current expectations was recognized by Morningstar:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine cost of capital.[73]

Because he failed to look directly at the returns investors are currently requiring in the capital markets, Dr. Woolridge's CAPM estimate significantly understates investors' required rate of return.

Q. IS THERE ANYTHING FORWARD-LOOKING ABOUT THE ACADEMIC STUDIES REFERENCED BY DR. WOOLRIDGE?

A. No. As Dr. Woolridge summarized (Exhibit JRW-7, p. 3), his CAPM analysis was based on risk premiums derived from various academic studies and other publications. Rather than looking directly at the returns investors might currently be requiring in today's capital markets, Dr. Woolridge predicated his CAPM study on a summary of *historical* results from selected sources in the academic and trade literature. These studies reflect historical data, not the current expectations of the future that form the basis of investors' required returns today. This critical distinction was recognized in a survey of risk premium research:

> The debate surrounding the equity risk premium arises because theoretically such premia are concerned with the extent to which risky stocks are "expected" to outperform a (relatively) safe investment, whereas excess returns are

[72] Woolridge Direct at 40-41.
[73] Morningstar, *Ibbotson SBBI, 2008 Valuation Yearbook* at 23.

> estimated values of this outperformance derived from observed data. The lack of consensus regarding the true value of the equity risk premium arises from the fact that expectations are unobservable hence can only be estimated, and that such estimates will vary over time depending, in part at least, on the sample period used.[74]

In other words, instead of directly considering requirements in today's capital markets, Dr. Woolridge is implicitly asserting that events and expectations for the time periods covered by his subset of studies are more representative of what is likely to occur going forward. This assertion runs counter to the assumptions underlying the use of the CAPM to estimate investors' required return, which is a purely forward-looking model.

Moreover, even if historical studies were relevant in this context, there are other such studies of equity risk premiums published in academic journals that imply required rates of return considerably in excess of those selected by Dr. Woolridge. For example, a study of equity risk premiums over the period 1889 through 2000 reported in the *Financial Analysts' Journal* directly contradicted Dr. Woolridge's assertion that investors are likely to anticipate sharp declines in the equity risk premium for U.S. stocks:

> Over the long term, the equity risk premium is likely to be similar to what it has been in the past and returns to investment in equity will continue to substantially dominate returns to investments in T-bills for investors with a long planning horizon.[75]

[74] Oyefeso, Oluwatobi, "Would There Ever Be Consensus Value and Source of the Equity Risk Premium? A Review of the Extant Literature," *International Journal of Theoretical and Applied Finance*, Vol. 9, No. 2 (2006) 199–215.
[75] Mehra, Ranjnish, "The Equity Premium: Why Is It a Puzzle?", *Financial Analysts' Journal* (January/February 2003).

Similarly, based on a study of *ex-ante* expected returns for a sample of S&P 500 firms over the 1983-1998 period, a 2003 article in *Financial Management* found an expected market risk premium of 7.2 percent.[76]

In contrast to the conclusions that Dr. Woolridge draws from his review of selected studies, other researchers are less sanguine and recognize that the shortcomings of academic methods can produce results that deviate from investors' actual expectations and requirements:

> The above discussion suggests that the equity premium debate is far from over, and that the use of excess returns as a proxy for such premia, while convenient, may capture a substantial amount of noise and be uncorrelated with equity risk premia particularly over the short-run.[77]

In fact, no selected historical study, or group of studies, is a substitute for an analysis of investors' current expectations in the capital markets, such as that incorporated in my CAPM analysis shown on Schedules WEA-5 and WEA-6.

Q. WHAT IS THE SECOND INDICATION THAT THE STUDIES REFERENCED BY DR. WOOLRIDGEHILL DO NOT REFLECT INVESTORS' EXPECTATIONS?

A. Many of the results of the equity risk premium studies reported by Dr. Woolridge do not make economic sense. As shown on page 3 of Dr. Woolridge's Exhibit JRW-7, 16 of the 38 historical studies included in Dr. Woolridge's assessment found market equity risk premiums of 4.2 percent or below. But multiplying a market equity risk premium of 4.2 percent by Dr. Woolridge's beta of 0.82 for his proxy group, and combining the resulting 3.4 percent risk premium with his 4.5 percent risk-free rate,

[76] Harris, R.S., Marston, F. C., Mishra, D. R., and O'Brian, T. J., "Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," *Financial Management* (Autumn 2003) at Table I.
[77] Oyefeso, Oluwatobi, "Would There Ever Be Consensus Value and Source of the Equity Risk Premium? A Review of the Extant Literature," *International Journal of Theoretical and Applied Finance*, Vol 9, No. 2 (2006) 199–215.

results in an indicated cost of equity of less than 8.0 percent, which falls below the yields investors can now earn by investing in triple-B rated utility bonds. By any objective measure, such results fall woefully short of required returns from an investment in common equity and confirm that Dr. Woolridge's CAPM cost of equity has little relation to the expectation of real-world investors.

Q. ARE THE RESULTS OF DR. WOOLRIDGE'S "BUILDING BLOCK" APPROACH (P. 45-51) ANY MORE INDICATIVE OF FORWARD-LOOKING, *EX-ANTE* EXPECTATIONS?

A. No. Dr. Woolridge applied his "building block" approach based on backward-looking, historical data for certain key variables. For example, Dr. Woolridge noted that one key component of his estimated market return was based on "the *historical* real earnings growth rate for the S&P 500."[78] Similarly, his conclusion that investors would not expect any further increases in the P/E ratios of common stocks going forward was based largely on his review of P/E ratios for the S&P 500 over the last 25 years.[79]

Q. WHAT EVIDENCE DEMONSTRATES THAT DR. WOOLRIDGE'S "BUILDING BLOCK" APPROACH RESTS ON A WEAK FOUNDATION?

A. Dr. Woolridge based his "building block" analysis of the market equity risk premium on an article by Roger G. Ibbotson and Peng Chen, published in *Financial Analysts' Journal*. But Dr. Woolridge's conclusions differ markedly from those of the authors of the article on which his "building blocks" approach was based. Based on the results of their study, Ibbotson and Chen concluded that:

[78] Woolridge Direct at 49.
[79] Woolridge Direct at 49-50.

> Our forecast of the equity risk premium is only slightly lower than the pure historical return estimate. We estimate the expected long-term equity risk premium ... to be about 6 percentage points arithmetically...[80]

Meanwhile, Dr. Woolridge asserted that the methods outlined by Ibbotson and Chen currently suggest a market risk premium of approximately 4.54 percent. In other words, Dr. Woolridge is contending that the market equity risk premium has decreased by approximately 146 basis points -- a decline of 24 percent -- since the time Ibbotson and Chen published their study in early 2003. Of course, there is no underlying capital market evidence for such a tremendous downward shift in the market equity risk premium at a time when investors' sensitivity to risk is widely understood to have increased dramatically. The fact that the results of Dr. Woolridge's "building blocks" approach cannot be reconciled to observable capital market trends or the results of the original study demonstrates the fatal flaws inherent in his method.

Similarly, the 8.7 percent rate of return on the stock market as a whole that results from Dr. Woolridge's "building blocks" approach falls 120 basis points below his recommended ROE for LGE's electric operations and 50 basis point less than his anemic ROE for LGE's gas utility, despite the fact that his beta values indicate a lower level of investment risk for utilities. This violates the risk-return tradeoff that is fundamental to finance and further illustrates the frailty of Dr. Woolridge's analyses.

Q. DOES THE *SURVEY OF PROFESSIONAL FORECASTERS,* CITED BY DR. WOOLRIDGE (P. 55), PROVIDE ANY MEANINGFUL CORROBORATION OR GUIDANCE AS TO INVESTORS' REQUIRED RATE OF RETURN?

A. No. The *Survey of Professional Forecasters* is not an investment advisory publication; nor is this report focused on serving as a resource for stock market

[80] Ibbotson, Roger G. and Peng Chen, "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts' Journal* at 88 (January/February 2003).]

investors. Rather, this survey primarily targets broad indicators of macroeconomic performance, such as GDP and its components, unemployment rates, industrial production, and inflation. While the survey may provide a useful resource for policymakers and in general business planning, it is not widely referenced by *investment professionals as a guide to stock market performance or routinely used in* estimating investors' required rate of return.

Indeed, as Dr. Woolridge indicated, the *Survey of Professional Forecasters* apparently predicts that equity returns for the S&P 500 will amount to 6.8 percent. Meanwhile, Moody's reported that the average yield on triple-B corporate bonds was 7.7 percent during November 2008.[81] Why would rational investors buy a basket of common stocks, and assume all the inherent risk, in exchange for an expected return that falls 90 basis points *below* the return they could earn with certainty by buying a bond? The answer, of course, is that rational investors would not. Considering that this 6.8 percent implied return falls 310 basis points below even Dr. Woolridge's downward biased 9.9 percent cost of equity recommendation for LGE's electric operations, this result is clearly nonsensical.[82]

Q. DO THE RISK PREMIUMS "OF LEADING INVESTMENT FIRMS" CITED BY DR. WOOLRIDGE (P. 54) PROVIDE ANY SUPPORT FOR HIS CONCLUSIONS?

A. No. Like the data from the *Survey of Professional Forecasters*, these observations provide no meaningful guidance as to a fair rate of return for LGE. Dr. Woolridge

[81] Moody's Investors Service, www.credittrends.com (retrieved Dec. 4, 2008).

[82] This 6.8 percent market return is 240 basis points shy of Dr. Woolridge's ROE recommendation for LGE's gas utility operations. Similarly, Dr. Woolridge's reference (p. 52) to the 3.99 percent equity risk premium from a 2008 CFO survey implies a cost of equity to his utility group of approximately 7.8 percent, which is at or below current yields on long-term utility bonds.

cites a market risk premium "in the 2.0 - 3.0 percent range" based on his two selected sources. Multiplying the 2.5 percent midpoint of this range by Dr. Woolridge's beta value of 0.82, and then adding the resulting 2.1 percent risk premium to his 4.5 percent risk free rate, results in an implied cost of equity for an electric utility of 6.6 percent. In light of the yields available on long-term debt, plain common sense tells us that this result is simply meaningless. Rather than confirming Dr. Woolridge's testimony, it provides one more indication of just how far his analyses and opinions are from those of investors in the capital markets.

Q. WHAT ABOUT DR. WOOLRIDGE'S REFERENCE (P. 55-56) TO THE RISK PREMIUMS OF "LEADING CONSULTING FIRMS"?

A. Dr. Woolridge's reference to a 2002 McKinsey & Co. study demonstrates the fallacy of his focus on selected historical information to apply the CAPM. As Dr. Woolridge noted, in an effort to explain their observations regarding the behavior of equity risk premiums, McKinsey & Co. concluded that equities had not become less risky. Rather, they surmised that investors' required returns on government bonds had increased due to concerns over the potential impacts of "inflation shocks." But just the opposite is true today. Long-term government bonds have been largely viewed as a safe haven as stock market volatility and a resulting "flight to quality" have driven bond yields sharply lower. Moreover, with the economy in decline and dramatic plunges in the prices of commodities, there is no evidence that an anticipated "inflation shock" similar to those of the 1970s would suggest a secular decline in the equity risk premium going forward. Considering that the historical premise underlying the conclusions of the McKinsey study does not reflect current capital market expectations, this reference provides no useful information in gauging investors' current required rates of return.

Q. DR. AVERA, ARE YOU IN ANY WAY ALLEGING THAT ALL THESE STUDIES AND SURVEYS ARE INHERENTLY FLAWED?

A. No, not at all. The point that I am making is that there is more than one way to define and calculate an equity risk premium. The problem with Dr. Woolridge's approach is that, instead of looking directly at an equity risk premium based on current expectations – which is what is required in order to properly apply the CAPM – he undertakes an unrelated exercise of compiling a list of selected computations culled from the historical record. Average realized risk premiums computed over some selected time period may be an accurate representation of what was actually earned in the past, but they don't answer the question as to what risk premium investors were actually expecting to earn on a forward-looking basis during these same time periods. Similarly, calculations of the equity risk premium developed at a point in history – whether based on actual returns in prior periods or contemporaneous projections – are not the same as the forward-looking expectations of today's investors, which are premised on an entirely different set of capital market and economic expectations.

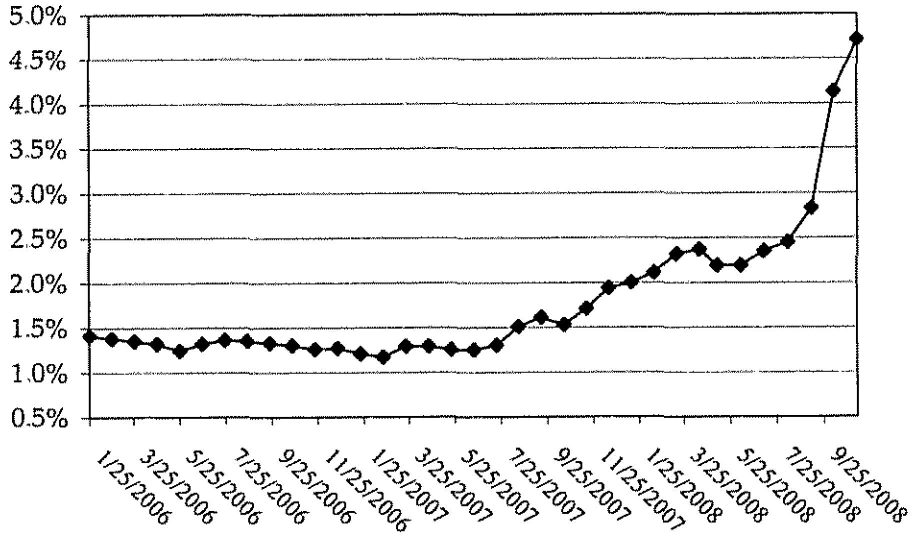
Likewise, surveys of selected corporate executives or economists, or building blocks based on academic research, are not equivalent to investors' required returns in the coming period. Since the benchmark for a fair ROE requires that the utility be able to compete for capital in the current capital market, the relevant inquiry is to determine the return that real world investors in today's markets require from LGE in order to compete for capital with other comparable risk alternatives. In short, while there are many potential definitions of the equity risk premium, the only relevant issue for application of the CAPM in a regulatory context is what return investors currently expect to earn on money invested today in the risky market portfolio versus the risk-free U.S. Treasury alternative. In contrast to Dr. Woolridge, my approach represents a straightforward and direct approach to answer this very question. As the old saying goes, "If all you have is a hammer, everything looks like a nail." All the pounding in the world will not turn the historical data cited by Dr. Woolridge into the forward-looking expectations required by the CAPM.

Q. ARE THERE OTHER REASONS WHY DR. WOOLRIDGE'S CAPM RESULT FALLS BELOW INVESTORS' FORWARD-LOOKING RATE OF RETURN?

A. Yes. Applying the CAPM by adding an historical risk premium to current Treasury bond yields, as Dr. Woolrdige has done, is complicated by the impact of the unprecedented financial crisis on investors' risk perceptions and required returns. Dr. Woolridge's backward-looking approach incorrectly assumes that investors' assessment of the relative risk differences, and their required risk premium between Treasury bonds and common stocks is constant and equal to some historical average. At no time in recent history has the fallacy of this assumption been demonstrated more concretely.

As discussed earlier, while the required returns for common stocks and public utility bonds have moved sharply higher to compensate for increased perceptions of risk, the yields on Treasury securities have fallen significantly or remained flat. This "flight to quality" has caused the spread between the observable yield on triple-B rated utility bonds and 20-year Treasury bonds to spike dramatically. Figure WEA-3, below, plots the monthly spread between triple-B public utility bond yields and 20-year Treasury bond yields since January 2006:

FIGURE WEA-3
BBB UTILITY – 20-YR. TREASURY YIELD SPREAD



As illustrated above, beginning in mid-2007, spreads between 20-year government bonds and triple-B utility bonds began to widen, with the disparity becoming more pronounced as the extent of the challenges facing the financial system and economy became increasingly clear to investors. During 2007, this yield spread averaged 142 basis points, versus 270 basis point in 2008 year-to-date, and 471 basis points in November 2008.

Q. WHAT DOES THIS IMPLY WITH RESPECT TO DR. WOOLRIDGE'S CAPM ANALYSIS?

A. Because Dr. Woolridge's analysis consisted of adding a fixed, historical risk premium to current yields on government bonds, it fails to account for the impact of the "flight to quality" and the significantly higher risk premiums over Treasury bonds that investors now require to hold utility bonds and common stocks. This is yet another indication that Dr. Woolridge's results ignore the view of real-world investors in today's capital markets and fail the standards underlying a fair rate of return, which require that the ROE allow LGE the opportunity to earn a return commensurate with other investments of comparable risk.

Q. WHAT OTHER CONSIDERATIONS RESULT IN A DOWNWARD BIAS TO DR. WOOLRIDGE'S RISK PREMIUM?

A. As noted on page 3 of Dr. Woolridge's Exhibit JRW-7, many of the historical studies included in his analysis reported equity risk premiums based on geometric averages. While both the arithmetic and geometric means are legitimate measures of average return, they provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The arithmetic mean measures what the expected return would have to be each period to achieve the realized change in value over time.

In estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. When referencing realized rates of return in the past, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods. *Regulatory Finance: Utilities' Cost of Capital* had this to say:

> One major issue relating to the use of realized returns is whether to use the ordinary average (arithmetic mean) or the geometric mean return. *Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital.* When using historical risk premiums as a surrogate for the expected market risk premium, the relevant measure of the historical risk

> premium is the arithmetic average of annual risk premiums over a long period of time.[83]

Similarly, Morningstar concluded that:

> For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. ... The geometric average is more appropriate for reporting past performance, since it represents the compound average return.[84]

I certainly agree that both geometric and arithmetic means are useful, since my Ph.D. dissertation was on the usefulness of the geometric mean.[85] But the issue is not whether both measures can be useful; it is which one best fits the use for a forward-looking CAPM in this case. One does not have to get deep into finance theory to see why the arithmetic mean is more consistent with the facts of this case. The Commission is not setting a constant return that LGE is guaranteed to earn over a long period. Rather, the exercise is to set an expected return based on test year data. In the real world, LGE's yearly return will be volatile, depending on a variety of economic and industry factors, and investors do not expect to earn the same return each year. The usefulness of the arithmetic mean for making forward-looking estimates was confirmed in *Quantitative Investment Analysis* (2007), one of the textbooks included in the study curriculum for the Chartered Financial Analyst designation, which concluded that the arithmetic mean is the appropriate measure when calculating an expected equity risk premium in a forward-looking context.[86] Just as importantly, by relying directly on expectations and estimates of investors' required rate of return, as

[83] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utilities Reports (1994) at 275, (emphasis added).
[84] Morningstar, *Ibbotson SBBI 2008 Valuation Yearbook* at 77.
[85] William E. Avera, *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice* (1972).
[86] DeFusco, Richard A., Dennis W. McLeavey, Jerald E. Pinto, and David E. Runkle, *Quantitative Investment Analysis*, John Wiley & Sons, Inc. (2007) at 128.

incorporated in the CAPM analysis presented on my Exhibits WEA-5 and WEA-6, there is no need to debate the merits of geometric versus arithmetic means, since neither is required to apply this forward-looking approach.

Q. WHAT DOES THIS IMPLY WITH RESPECT TO THE CONCLUSIONS OF DR. WOOLRIDGE'S CAPM ANALYSIS?

A. For a variable series, such as stock returns, the geometric average will <u>always</u> be less than the arithmetic average. Accordingly, Dr. Woolridge's reference to geometric average rates of return provides yet another element of systemic downward bias.

Q. DOES DR. WOOLRIDGE (P. 8) ACCURATELY CHARACTERIZE THE STATEMENTS OF ALAN GREENSPAN?

A. No. Dr. Woolridge's selective quotation ignores both the context and the message of Mr. Greenspan's remarks. First, it is important to note that Mr. Greenspan's comments were made in October 1999, at a time when sharply rising equity valuations were giving rise to concern over "irrational exuberance." Rather than predicting continued expectations for lower risk premiums, Mr. Greenspan's October 1999 speech warned his audience not to be complacent. Mr. Greenspan noted that any decline in equity risk premiums could prove to be temporary – an observation that has been borne out by the recent collapse in equity values – and he specifically predicted that sharply rising risk premiums could lead to crisis if not addressed beforehand. As Mr. Greenspan noted:

> ...history tells us that sharp reversals in confidence can occur abruptly, most often with little advance notice. These reversals can be self-reinforcing processes that can compress sizeable adjustments into a very short period. ... The uncertainties inherent in valuations of assets and the potential for abrupt

> changes in perceptions of those uncertainties clearly must be adjudged by risk managers...[87]

Rather than supporting Dr. Woolridge's anemic ROE recommendation, Mr. Greenspan's cautions over the potential for swift and sharp reversals is entirely consistent with my testimony that it is absolutely necessary to consider both current capital market realities and the need to provide adequate support for LGE's financial integrity.

Q. WHAT ABOUT DR. WOOLRIDGE'S VIEW THAT THE MARKET RETURN USED IN YOUR FORWARD-LOOKING CAPM ANALYSIS (SCHEDULES WEA-5 AND WEA-6) IS "EXCESSIVE"?

A. As explained earlier and in my direct testimony, I estimated the current equity risk premium by first applying the DCF model to estimate investors' current required rate of return for the firms in the S&P 500 and then subtracting the yield on government bonds. Dr. Woolridge contends that this CAPM analysis is flawed because of an alleged upward bias in the analysts' growth estimates used to estimate investors' expected return on the S&P 500.

The fallacy of these arguments was addressed earlier in my discussion of the DCF model. Moreover, Dr. Woolridge also relied on analysts' estimates in applying the DCF model and, as indicated earlier, the use of forward-looking expectations in estimating the market risk premium is well accepted in the financial literature. For example, the table on page 41 of Dr. Woolridge's testimony noted that: Current financial market prices (simple valuation ratios or DCF-based measures) can give most objective estimates of feasible ex ante equity-bond risk premium.

Dr. Woolridge went on to note that "Fama and French conclude that ex ante equity risk premium estimates using DCF models and fundamental data are superior to those

[87] "Measuring Financial Risk in the Twenty-first Century," *Remarks by Alan Chairman Greenspan* (Oct. 14, 1999).

using ex post historic stock returns."[88] In fact, this straightforward application of the DCF model to the S&P 500 using current financial market data is exactly the approach reflected in my forward-looking application of the CAPM presented in Schedules WEA-5 and WEA-6.

I grant that my forward-looking CAPM approach produces an equity risk premium for the S&P 500 that is significantly higher than his unrealistic benchmarks. But rather than look backwards to a select subset of academic studies, or a "building blocks" risk premium based largely on historical data, as Dr. Woolridge advocates, but as discussed earlier, my analysis appropriately focused on the expectations of actual investors in today's capital markets.

Q. APART FROM YOUR EARLIER DISCUSSION, WHAT OTHER EVIDENCE INDICATES THAT THE MARKET RETURN USED IN YOUR CAPM ANALYSIS IS NOT INFLATED?

A. While Dr. Woolridge argues that the 10.9 percent expected growth rate and resulting 13.3 percent market return that I used to apply the CAPM are "clearly not realistic," his own exhibits and sources contradict his personal view. Consider page 5 of Exhibit JRW-7, for example, which presents historical earnings for the S&P 500. In 19 of the years included in Dr. Woolridge's table, growth in earnings exceeded the 10.9 percent forward-looking estimate used to compute my market rate of return. Similarly, Morningstar reported that since 1926 the actual realized return on large-company stocks exceeded the 13.3 percent forward-looking estimate used in my CAPM analysis in half those years, in many cases by a considerable margin.[89] Indeed Dr. Woolridge

[88] Woolridge Direct at 42.
[89] Morningstar, *Ibbotson SBBI 2008 Valuation Yearbook* at Table B-1.

quotes Professor Jeremy Siegel's 1999 book, *Stocks for the Long Term,* concluding, "[T]he return on equities is likely to fall from its historical levels due to the very high level of equity prices relative to fundamentals."[90] But times have changed over the past decade, as the same Professor Siegel recognized in a much more recent statement:

> But I believe that stock prices are now so extraordinarily cheap that I would be very surprised that if an investor who bought a diversified portfolio today did not make at least 20% or more on his investment in the next twelve months.
>
> **Valuations Low Worldwide**
>
> The case for equities at these levels is compelling. The last time we have seen prices this low was more than 30 years ago, when the US economy was in far worse shape than today.[91]

Professor Siegel has clearly recognized that stock prices have crashed through the 1999 highs and now are very low relative to fundamentals. The same Professor Siegel that Dr. Woolridge invoked as an authority supporting low return expectations is now telling investors that high returns are to be expected given the dramatic fall in stock prices relative to fundamentals.

D. Other Issues

Q. DOES DR. WOOLRIDGE'S DISCUSSION OF MARKET-TO-BOOK RATIOS (PP. 14-17, 79) PROVIDE ANY MEANINGFUL BASIS ON WHICH TO EVALUATE THE COST OF EQUITY FOR LGE?

A. No. The argument that regulators should set a required rate of return to produce a market-to-book value of approximately 1.0 is fallacious. As noted in *Regulatory Finance: Utilities Cost of Capital*:

> The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulation should

[90] Woolridge Direct at 7.

[91] Siegel, Jeremy, "Why Stocks Are Dirt Cheap," *The Future for Investors*, www.finance.yahoo.com (Oct. 31, 2008).

> set an allowed rate of return so as to produce a M/B of 1.0, presumes that investors are masochistic. They commit capital to a utility with a M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is not a realistic or accurate view of regulation.[92]

With market-to-book ratios generally above 1.0 times, Dr. Woolridge apparently believes that, unless book value grows rapidly, regulators should establish equity returns that will cause share prices to fall. Within the paradigm of DCF theory, a drop in stock prices means negative growth, and if investors expect negative growth then this is the relevant "g" to substitute in the constant growth DCF model. In turn, a negative growth rate implies a DCF cost of equity for utilities less than their dividend yields. This, of course, is truly a nonsensical result, and a manifestation of the failings of Dr. Woolridge's arguments.

V. LANE KOLLEN

Q. DID MR. KOLLEN CONDUCT AN INDEPENDENT STUDY TO ESTIMATE A FAIR ROE FOR LGE?

A. No. Mr. Kollen did not perform any independent analyses to support his assertions regarding LGE's ROE. Rather, his assessment was based entirely on inaccurate comparisons with average historical authorized rates of return for the first three quarters of 2008.

Q. PLEASE DISCUSS THE FLAWS IN MR. KOLLEN'S EVALUATION.

A. First, these historical figures completely ignore the significant changes in capital market conditions since the record in these various proceedings was established. As indicated earlier, the increase in utility bond yields translates to an upward adjustment in investors required rate of return. Over the first three quarters of 2008, the yield on

[92] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utilities Reports, Inc. (1994) at 265

triple-B public utility bonds averaged approximately 6.8 percent, or 6.3 percent in 2007 when the record evidence in many of these proceedings was likely established. Compared to an average yield of 9.0 percent in November 2008, this results in an increase of 220 basis points and 270 basis points, respectively. As a result, adjusting the stale, historical figures underlying Mr. Kollen's analysis of authorized returns would suggest a significant increase in the return on equity. As noted earlier, this is consistent with the investment community's view that "significantly higher regulated returns will be required to attract equity capital."[93]

Second, while Mr. Kollen subjectively adjusted the reported ROE data to remove certain higher returns associated with generating activities, he made no effort to examine the remaining values to ensure that they applied to the integrated electric utility services provided by LGE. For example, included in Mr. Kollen's analysis was a 9.4 percent ROE authorized for Connecticut Light & Power Company ("CL&P"), a 9.1 percent ROE authorized for Consolidated Edison of New York ("ConEd"), and a 9.4 percent ROE authorized for Orange and Rockland Utilities ("O&R"). While CL&P, ConEd, and O&R formerly operated as vertically integrated utilities, they have largely divested their generating assets in response to restructuring in their respective jurisdictions. As a result, they are essentially "wires" companies that provide energy delivery service, which is distinct from the integrated electric utility service provided by LGE. Accordingly, to be internally consistent with his own flawed approach, Mr. Kollen should have removed these values in addition to observations related solely to generation activities. Just as importantly, like Dr. Woolridge's revenue test, Mr.

[93] Fitch Ratings Ltd., "EEI 2008 Wrap-Up: Cost of Capital Rising," *Global Power North America Special Report* (Nov 17, 2008).

Kollen's argument and approach was entirely divorced from objective measures of the overall risks perceived by investors, such as credit ratings.

Q. WHAT IS THE AVERAGE AUTHORIZED ROE AFTER MAKING THESE CORRECTIONS?

A. Correcting Mr. Kollen's approach for this internal inconsistency results in an average ROE of 10.44 percent. Although this is higher than the value he cites, it remains significantly downward biased because, as explained above, it fails to reflect the sharply higher returns that investors now require to invest in long-term capital.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

VERIFICATION

STATE OF TEXAS)
) **SS:**
COUNTY OF TRAVIS)

The undersigned, **William E. Avera**, being duly sworn, deposes and says that he is President of FINCAP, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

WILLIAM E. AVERA

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of December, 2008.

Notary Public (SEAL)

My Commission Expires:

1/10/2011

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm Exp Jan 10. 2011

WOOLRIDGE PROXY GROUPS

		(a) Stock Price	(b) Dividend	Dividend Yield
	Electric Proxy Group			
1	ALLETE, Inc.	$ 34.34	$ 1.78	5.18%
2	Ameren Corp.	$ 32.85	$ 2.54	7.73%
3	American Elec. Pwr.	$ 30.44	$ 1.76	5.78%
4	Central Vermont PS	$ 19.31	$ 0.92	4.76%
5	Cleco Corp.	$ 21.90	$ 0.90	4.11%
6	DPL, Inc.	$ 20.94	$ 1.10	5.25%
7	Edison Intnl.	$ 33.40	$ 1.29	3.86%
8	Empire District	$ 18.01	$ 1.28	7.11%
9	FirstEnergy Corp.	$ 54.59	$ 2.40	4.40%
10	FPL Group	$ 46.36	$ 1.88	4.06%
11	Hawaiian Electric	$ 26.51	$ 1.24	4.68%
12	IDACORP, Inc.	$ 28.41	$ 1.20	4.22%
13	Northeast Utilities	$ 22.35	$ 0.88	3.94%
14	NSTAR	$ 33.19	$ 1.50	4.52%
15	Pinnacle West	$ 29.67	$ 2.10	7.08%
16	PNM Resources	$ 9.03	$ 0.50	5.53%
17	Progress Energy	$ 38.68	$ 2.46	6.36%
18	Southern Company	$ 35.01	$ 1.73	4.94%
19	UIL Holdings	$ 30.66	$ 1.73	5.64%
20	UniSource Energy	$ 25.70	$ 0.96	3.74%
21	Xcel Energy	$ 17.85	$ 0.97	5.43%
	Average			**5.16%**
	Gas Proxy Group			
1	AGL Resources	$ 29.15	$ 1.71	5.87%
2	Atmos Energy	$ 23.74	$ 1.32	5.56%
3	Laclede Group, Inc.	$ 51.67	$ 1.53	2.96%
4	New Jersey Resources	$ 37.00	$ 1.24	3.35%
5	Nicor Inc.	$ 40.56	$ 1.86	4.59%
6	Northwest Natural Gas	$ 48.92	$ 1.58	3.23%
7	Piedmont Natural Gas	$ 32.42	$ 1.04	3.21%
8	South Jersey Industries	$ 35.52	$ 1.12	3.15%
9	Southwest Gas	$ 24.89	$ 0.92	3.70%
10	WGL Holdings	$ 32.83	$ 1.44	4.39%
	Average			**4.00%**

(a) Average closing price for November 2008 from www.finance.yahoo.com.

(b) Estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (Nov. 28, 2008).

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	))))	CASE NO. 2008-00252

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	CASE NO. 2007-00564

REBUTTAL TESTIMONY OF
VALERIE L. SCOTT
CONTROLLER
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: December 19, 2008

Q. *Please state your name, position and business address.*

A. My name is Valerie L. Scott. I am the Controller for Louisville Gas and Electric Company ("LG&E" or the "Company"), and an employee of E.ON U.S. Services, Inc., which provides services to LG&E and Kentucky Utilities Company ("KU") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky.

Q. Have you submitted direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut certain contentions concerning the calculation of LG&E's revenue requirements raised by Robert Henkes, for the Office of the Attorney ("AG"), and Lane Kollen, for the Kentucky Industrial Utility Customers, Inc. ("KIUC"). In addition, I will respond to the recommendation of the AG's witness, Michael Majoros, concerning his recommendation for the cost of removal regulatory liability to be reclassified from accumulated depreciation to Account 254 – Other Regulatory Liabilities for Regulatory Accounting, Reporting and Ratemaking Purposes.

<u>Synchronized Interest Expense Level</u>

Q. Do you agree with the recommendation made by Mr. Henkes concerning the calculation of the pro forma synchronized interest expense level?

A. I agree in concept, but not in his application. Both LG&E and the AG appear to agree on the need for the adjustment and how it is to be calculated, but differ on the amount of capitalization and weighted cost of debt to be used in the calculation. Mr. Henkes' calculation uses the AG's recommended capitalization and weighted cost of debt numbers, which are different from those proposed by LG&E. LG&E's recommended synchronized interest level is based on a fair, just, and reasonable level of adjusted capitalization, as discussed in Mr. Rives' rebuttal testimony, and should be used in the calculation of the adjustment.

MISO Net Expense Adjustment

Q. Please comment on the recommendation of Mr. Henkes concerning LG&E's proposed "MISO net expense adjustment."

A. This adjustment relates to the Company's proposed base rate treatment of the Midwest Independent Transmission System Operator, Inc. ("MISO") exit regulatory asset and Schedule 10 regulatory liability. The calculation of the adjustment nets the cumulative Schedule 10 regulatory liability with the MISO exit fee regulatory asset, and then implements a five year amortization of the remaining net exit fee asset as of the end of the test year. The AG's witness, Mr. Henkes, agrees with the Company's proposals to amortize the net balance of the MISO exit fees and cumulative MISO Schedule 10 collections over a five year period. Although Mr. Henkes said in his direct testimony that he did not agree with LG&E's proposal to limit the amortization of the actual balances existing at the end of the test year while leaving the rate recognition for continuing post-test year MISO exit fee credits and MISO Schedule 10 collections until the next base rate case, he subsequently reversed his opinion in his responses to questions in discovery, and now agrees with LG&E's approach and its proposed MISO net expense adjustment.[1]

[1] *See* Case No. 2008-00251, AG's Responses to DRs of Commission Staff, DR No. 3 (Dec 3 2008), Case No. 2008-00252, AG's Responses to DRs of Commission Staff, DR No. 4 (Dec. 3 2008)

Coal Tax Credit

Q. Do you agree with Mr. Henkes' recommendation that LG&E's adjustment to remove the Kentucky Coal Tax Credit from the test year should be rejected?

A. No. The coal tax credit is contingent on LG&E's annual level of Kentucky coal purchases versus the 1999 baseline of purchases and will expire by law for purchases made in 2009. LG&E cannot be reasonably certain as to whether it will purchase sufficient amounts of Kentucky coal to qualify for the credit each year. Purchases of Kentucky coal are dependent upon a number of factors that are beyond LG&E's control, including availability, price, vendor performance at the mine and transportation of the coal to the electric generation facility. Weather also affects the amount of coal LG&E will purchase and the ability to deliver that coal to the electric generation facilities. The impact of these variables is plainly demonstrated by the fact that LG&E did not qualify for the coal tax credit in 2000 and 2001. For these reasons, it is unreasonable to assume, as Mr. Henkes does, that LG&E will continue to be able to purchase sufficient quantities of Kentucky coal that can be delivered to the generation stations that will allow LG&E to utilize this tax credit.

Moreover, the fact that the amount of the Kentucky Coal Tax Credit varies from year to year further shows the need to remove the credit from the calculation of the revenue requirement.

Q. Does the normalization of the coal tax credit as proposed by Mr. Kollen effectively resolve the volatility associated with the amount of the Kentucky Coal Tax Credit?

A. No. Mr. Kollen annualized the first quarter of 2008 of this credit in developing the amount he then applied to the determination of the revenue requirement rather than using the actual credit included in the test year. Likewise, using the annualized credit for first quarter of 2008 to "normalize" the credit is not sound ratemaking as it uses the second highest coal credit ever projected to be received as its basis and is clearly designed to achieve a higher result. Mr. Kollen's proposal ignores the fact that LG&E received no coal tax credit in some past years because its Kentucky coal purchases did not exceed the base amounts. Moreover, it also ignores the amount of the Kentucky Coal Tax Credit included in the test period.

Q. Does the normalization of the coal tax credit as proposed by Mr. Henkes effectively resolve the volatility associated with the amount of the Kentucky Coal Tax Credit?

A. The normalization of the Kentucky Coal Tax Credit proposed by Mr. Henkes based on the average of the actual coal tax credit as experienced by LG&E in the most recent five year period is equally flawed. It conveniently overlooks the fact that LG&E did not receive coal tax credits in the years 2000 and 2001, thereby overstating the calculated normalized amount to achieve a higher result. Mr. Henkes' response to PSC Question No. 5 further overstates the calculated normalized amount to achieve an even higher result by using a normalization period of only the last three years.

Q. Why have the Commission and the Companies generally rejected normalization adjustments like those Messrs. Henkes and Kollen present for the coal tax credit?

A. The Commission and the Company have historically not used normalization of operations and maintenance expenses, with limited exceptions, and there is no Kentucky precedent to support a coal tax credit normalization adjustment, because such recommendations are very selective and result-oriented. Allowing such result-oriented adjustments would result in a series of selective adjustments the purpose of which would be to try to offset one another for the benefit of either the customer or the shareholders. It is for this good reason that the Commission has declined to allow such selective adjustments in the past; the exceptions are only for good cause, such as for storm damages and injuries and damages. Approval of this proposed adjustment would be a significant change to the historical and established rate-making process.

Q. Do you agree with Mr. Kollen's assertion that "the Companies' proposal constitutes a selective post-test year adjustment reaching into 2011, three years after the end of the test year?"

A. No. The fact that LG&E will continue to be eligible for the credit for purchases through 2009 and that the credit will be recorded on its books through 2010 does not change the highly contingent nature of the credit. As I previously explained, whether LG&E can purchase sufficient amounts of Kentucky coal depends on factors entirely beyond its control, including availability of such coal, the price of such coal versus the price of other comparable coal, vendor performance and transportation of the coal as well as the affect of weather on these variables.

Perhaps the greatest uncertainty concerning LG&E's receipt of the Coal Tax Credit from year to year is vendor performance. In 2008 alone, LG&E and KU have had numerous force majeure-related vendor failures because state and federal agencies are not issuing mining permits in Kentucky. For example, in eastern Kentucky the Companies' vendors are awaiting permits for 120,000 tons of coal supply for KU's Tyrone station and 120,000 tons of coal supply for KU's Ghent station. The Companies' western Kentucky vendors of medium and high sulfur coals have decreased their amounts supplied to LG&E and KU by approximately 1.8 million tons. Therefore, just in this calendar year alone, vendor performance issues have resulted in LG&E and KU receiving approximately two million fewer tons of Kentucky coal than they had anticipated.

Q. **Mr. Henkes has asserted that because LG&E has proposed, in this case, "to recognize for ratemaking purposes the amortization expense associated with the Mill Creek Ash Dredging regulatory asset which is scheduled in April 2010, it would be reasonable and consistent to give rate recognition to potential coal tax credit bookings which will not expire until December 2010." Do you agree with this argument?**

A. No. First, the Mill Creek Ash Dredging remains part of the environmental surcharge mechanism as approved by the Commission in its Order in Case No. 2004-00421.[2] This approval included the Mill Creek Ash Dredging deferred debit in the amount of $2,134,844. This amount is included in existing base rates and rate base. Thus, the recognition for ratemaking purposes of the amortization expense associated with the Mill Creek Ash Dredging regulatory asset is being treated entirely consistent with the operation of the environmental surcharge. This treatment has nothing to do with the contingent nature of the Kentucky Coal Tax Credit, which is, going forward, not known and measurable.

[2] The Commission's Order dated March 28, 2008 in Case #2007-00380, *In the Matter of: An Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Louisville Gas and Electric Company for the Six-Month Billing Period Ending October 31, 2006 and for the Two-Year Billing Period Ending April 30, 2007* however, did approve the incorporation of the environmental surcharge amounts into base rates.

Secondly, Mr. Henkes' assertion concedes the very contingent nature of the Kentucky Coal Tax Credit and the fact that it is not known and measurable going forward when he uses the word "potential" to describe the coal tax credit. In contrast, the Mill Creek Ash Dredging regulatory asset is known and measurable and approved for ratemaking purposes by the Commission's orders through the Environmental Surcharge Recovery mechanism.

Q. Mr. Henkes also asserts that because LG&E expects to file another rate case in conjunction with the commercial operation of Trimble County Unit No. 2 in the summer of 2010, the Commission should have "no concern that the rate recognition of potential coal tax credits through December 2010 will have a negative financial impact on LG&E." Do you agree with this argument?

A. No. The fact that LG&E expects to file a rate case when Trimble County Unit No. 2 commences commercial operation does not relieve the Commission from correctly deciding the issues in this case or somehow empowering the Commission to make result-oriented determinations in this case.

Q. Mr. Kollen has recommended in the alternative that if the Commission approves LG&E's proposed adjustment to remove the coal tax credit, the Commission should reflect the Section 199 increase from six percent to nine percent. Do you agree with this recommendation?

A. No. Section 199 is a domestic production activities deduction. It has no relationship to the Kentucky Coal Tax Credit. The production tax deduction available under Section 199 is already included in the tax calculation at the currently enacted rate, as demonstrated in Reference Schedule 1.39. Although this deduction may increase in the future as rates enacted for the future increase on future costs, the amount of the future deduction cannot be known at this time.

Recycle Tax Credit

Q. In LG&E's most recent past base rate case, did the AG agree with, and did the Commission approve, the removal of the Kentucky recycle tax credit from the test year in a pro forma adjustment?

A. Yes. In Case No. 2003-00433, LG&E's most recent base rate case, Mr. Henkes filed testimony for the AG did not take exception to LG&E's removal of the Kentucky recycle tax credit.[3] In its Final Order in that case, the Commission noted the AG's agreement without correction of twenty of LG&E's proposed pro forma operating income adjustments, including the "Adjustment for Prior Period Income Tax True-Ups and Adjustments for the Twelve Months Ended September 30, 2003," which the Commission also approved.[4]

Q. Have any circumstances changed since LG&E's last rate case that would now necessitate leaving the recycle credit in the test year or require amortizing the credit?

A. No, circumstances have not changed since LG&E's last rate case to necessitate leaving the recycle credit in the test year or require amortizing the credit. The recycle credit originated in 1999, and has been utilized on state income tax returns in subsequent years. In LG&E's last rate case test year there was an increase in income

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[3] *See 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, Direct Testimony and Exhibits of Robert J. Henkes Pertaining to the Electric Case at RJH-4 (Mar. 23, 2004); *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, Direct Testimony and Exhibits of Robert J. Henkes Pertaining to the Gas Case at RJH-4 (Mar. 23, 2004).

[4] *See 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, Order at 23-24 and Appx. F (June 30, 2004).

tax expense due to the timing of recording the recycle credit. LG&E removed this expense in a pro forma adjustment which was agreed to by the Attorney General and approved by the Commission. In this case a portion of the same recycle credit that originated in 1999 was recorded in the test year and removed as a pro forma adjustment for the same reason as the last rate case. The only difference from Case No. 2003-00433 was it decreased income tax expense in the current test year rather than increasing income tax expense in the last test year. Mr. Henkes' recommendation in this case is inconsistent with his approach in LG&E's last rate case.

Q. Do you agree with Mr. Henkes' recommendation that the Commission should reject LG&E's proposed adjustment to remove the recycle tax credit from the test year?

A. No. This adjustment properly removes an amount reflected during the test year that relates to prior periods. The Kentucky Recycle Credit was originally generated in 1999 in accordance with the requirements of KRS 141.390. The unused portion of the recycle credit is carried forward and used on Kentucky income tax returns, where possible, provided there is a tax liability. With his recommendation, however, Mr. Henkes is seeking to take improper advantage of an accounting mistake. As a result of reviewing prior year levels of LG&E's separate entity Kentucky taxable income, the entire recycle credit should have been recognized during the period 1999 through 2003. Consequently, E.ON U.S. LLC, the parent company of LG&E, paid LG&E for the remaining recycle credit in September 2008. Mr. Henkes' recommendation, however, seeks to unreasonably compound the improper impact of this inadvertent accounting oversight by amortizing the $4 million recycle credit over a five-year period as part of the revenue requirement and not including the unamortized balance as a deduction from rate base and capitalization.

Q. **Is LG&E's proposal to treat this tax credit as a prior period item "inconsistent" as Mr. Henkes asserts with his proposal in this case to reflect in the test year above-the-line operating expenses that involve an amortization of an unamortized balance?**

A. No. Including amortized expenses in the test year has nothing to do with the correction of an accounting mistake. Mr. Henkes' argument incorrectly assumes that the Kentucky Recycle Tax Credit should have been included on LG&E's books. In fact, it should not have been included on LG&E's books during the test year, and but for the inadvertent accounting oversight, it would not have been on LG&E's books.

Q. **Do you agree with Mr. Henkes' assertion that to remove the $4 million payment from the revenue requirement calculation is "inequitable to the ratepayers of LG&E?"**

A. No. The Commission should not include the $4 million credit in the calculation of the revenue requirement. This treatment truly would be inequitable because it is clearly designed to lower base rates and would improperly provide customers a benefit related to a prior period.

Labor Cost Adjustment and Employee Benefit Cost Adjustment

Q. **Do you agree with the labor cost adjustment and employee benefit cost adjustment proposed by Mr. Henkes proposed for LG&E?**

A. Yes. The Company identified these corrections in its discovery responses.

<u>Reporting Regulatory Liabilities for Cost of Removal</u>

Q. Do you agree with Mr. Majoros' recommendation that the Commission specifically recognize LG&E's regulatory liability for cost of removal as reported on its Generally Accepted Accounting Principles ("GAAP") statements as a regulatory liability for rate-making purposes?

A. No. LG&E should not be required to reclassify this amount from accumulated depreciation to Account 254 – Other Regulatory Liabilities for regulatory accounting, reporting, and rate-making purposes. It is important that we refrain from confusing financial reporting principles and regulatory ratemaking principles. They are not necessarily the same, and specifically are not the same in the area of reserves for cost of removal. LG&E's treatment of reserves for cost of removal is consistent with sound regulatory ratemaking principles and should be approved again by this Commission.

Q. What is the purpose of recording regulatory assets and liabilities?

A. The chief purpose of recording regulatory assets and liabilities is to assure that the economic effects of ratemaking are reflected in the financial statements when the recognition of revenues or costs for ratemaking purposes occurs in a different period than the period in which they would be recognized under GAAP by an unregulated entity. Only in limited circumstances do regulatory liabilities result from a requirement to provide refunds to customers. The Federal Energy Regulatory Commission, in its April 9, 2003 Final Rule, Order No. 631 in *Accounting, Financial Reporting, and Rate Filing Docket Requirements for Asset Retirement Obligations*, No. RM02-7-000, recognized that utilities subject to its accounting jurisdiction should simply keep subsidiary records of the amounts of removal costs recovered and incurred rather than establish a separate refundable regulatory liability. LG&E does just that.

Q. Is approval by the FERC Accounting Division required for such a change?

Yes. Based on CFR Ch. 1, Subchapter C, Part 101, paragraph E under Account No. 108, and confirmed by my conversation with the Accounting Division of FERC, FERC approval would be required to move regulatory liabilities for ratemaking purposes and reclassify them from accumulated depreciation to Account 254 – Other Regulatory Liabilities for regulatory accounting, reporting, and rate-making purposes.

Q. Mr. Majoros mentions the cost of removal of regulatory liabilities in connection with this recommendation and suggests that they are significant. Do you agree with this presentation of the information?

A. No. In his testimony, Mr. Majoros states that LG&E had reported $241 million in cost of removal of regulatory liabilities. Though this amount is significant in the abstract, it is a small percentage of LG&E's total plant in service. LG&E's $241 million in cost of removal is only 6.1% of LG&E's plant in service of $3.975 billion. LG&E's cost of removal at the end of the test year (April 30, 2008) was $245 million compared with the plant in service of $4.017 billion or 6.1%.

Q. Did the Commission address Mr. Majoros' recommendation in the previous rate cases?

A. Yes. Mr. Majoros concedes that the Commission has rejected his recommendations in previous cases. The Commission should continue to do so.

Q. Mr. Majoros asserts that because E.ON U.S. LLC does not file 10-K reports with the Securities and Exchange Commission that these amounts are no longer publicly available. Do you agree with his contention?

A. No. Although LG&E no longer files Forms 10-K or 10-Q with the Securities and Exchange Commission (SEC), it does prepare annual and quarterly financial statements which are provided to the Commission in accordance with the order in Case No. 2006-00445. Item No. 38 of the filing requirements in this case contains the type of annual and quarterly financial statements that LG&E prepares and provides to the Commission since it has ceased SEC reporting. In addition, LG&E files with FERC annual and quarterly reports containing the cost of removal balances. LG&E provides the Commission copies of these FERC filings as they are filed. Item No. 32 of the filing requirements in this case contains the most recent annual FERC Form 1 and LG&E's response to question six of the Kentucky Industrial Utility Customers, Inc.'s first data request in this case provided the quarterly FERC Forms 3 for the first and second quarters of 2008.

Finally, these amounts are clearly booked on LG&E's general ledger, which is available for inspection upon request from the Commission at any time. The balance of the cost of removal can also be provided in the form of regular and ongoing reports to the Commission should that be more preferable. Thus, there is not an issue with the Commission's oversight and inspection of this information. Reclassification is completely unnecessary to achieve this objective.

Q. What is your recommendation?

A. I recommend that the Commission continue to reject Mr. Majoros' recommendation consistent with its prior orders. To the extent the Commission desires to have more oversight of information currently provided to the Commission, LG&E will provide such additional reports as the Commission may request periodically or on an ongoing basis.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Valerie L. Scott,** being duly sworn, deposes and says she is the Controller for Louisville Gas and Electric Company, that she has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Valerie L. Scott
VALERIE L. SCOTT

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of December, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:
November 9, 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	)	**CASE NO. 2008-00252**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)	**CASE NO. 2007-00564**

REBUTTAL TESTIMONY OF SHANNON L. CHARNAS DIRECTOR OF UTILITY ACCOUNTING & REPORTING LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: December 19, 2008

Q. Please state your name, position and business address.

A. My name is Shannon L. Charnas. I am the Director of Utility Accounting and Reporting for Louisville Gas and Electric Company ("LG&E" or the "Company"), and an employee of E.ON U.S. Services, Inc., which provides services to LG&E and Kentucky Utilities Company ("KU"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Have you submitted direct testimony in this proceeding?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut certain adjustments proposed by the Attorney General's ("AG") witness, Mr. Robert Henkes, and the Kentucky Industrial Utility Customers, Inc.'s ("KIUC") witness, Mr. Lane Kollen. I will also address the recommendation by the AG's witness, Mr. Michael Majoros.

<u>Annualized Depreciation Expense</u>

Q. Does LG&E object to the annualized depreciation expense proposed by Mr. Henkes as shown on Schedule RJH-8 for LG&E electric operations and Schedule RJH-7 for LG&E gas operations?

A. Yes. The Schedule, according to Mr. Henkes, reflects the difference between the new depreciation rates proposed in this case by LG&E and the rates recommended by the AG's witness Mr. Majoros, as applied to the depreciable plant-in-service balances at the end of the test year. For the reasons stated in Mr. Spanos' rebuttal testimony, the depreciation rates recommended by Mr. Majoros are not reasonable and should be rejected. LG&E recommends the Commission approve the depreciation rates proposed in the testimony of Mr. Spanos and accept the adjustment to revenue requirement in Reference Schedule 1.14 and supported in my direct testimony.

Q. Does LG&E agree with the recommendation of Mr. Kollen that the equal life group depreciation procedure should be rejected and the average life group procedure should be maintained?

A. No. Mr. Kollen's reasons for recommending against the equal life group procedure are very similar to the reasons presented in the testimony of Mr. Majoros. As explained in the rebuttal testimony of Mr. Spanos, the objections are without merit and the equal life group procedure is more accurate than the average life group procedure for purposes of calculating depreciation expense. For these reasons, the Commission should reject Mr. Kollen's recommendations.

<u>**Net Negative Salvage**</u>

Q. Does LG&E agree with the recommendation of Mr. Kollen to reduce the Companies' net negative salvage rates to remove future inflation from the cost of removal component?

A. No. Mr. Kollen, in making his recommendation, is accepting the recommendation made by the AG's witness, Mr. Majoros on this subject. The calculation of the KIUC adjustment on this issue was taken directly from Mr. Majoros' testimony and used by Mr. Kollen for purposes of presenting the adjustment in his testimony. The rebuttal testimony of Mr. Spanos demonstrates why the recommendation of Mr. Majoros and now Mr. Kollen on the treatment of net negative salvage rates should be rejected. For these reasons, the Commission should reject Mr. Kollen's recommendation to reduce LG&E and KU's net negative salvage rates to remove future inflation from the cost of removal component.

Edison Electric Institute Dues

Q. Do you agree with Mr. Henkes' adjustment to the Edison Electric Institute dues?

A. No. Mr. Henkes has selected a percentage for his adjustment that was used five years ago in LG&E's last rate case to recommend a result-oriented adjustment. LG&E has provided the appropriate percentages of its Edison Electric Institute ("EEI") dues associated with lobbying activities in this case in LG&E's Data Response to PSC 3-31, which are 16.15% for regular activities, 35.86% for separately funded industry activities and 15.02% for separately funded environmental activities. The total lobbying expense for the EEI dues is $70,707. Mr. Henkes' recommendation to use the percentage used five years ago in LG&E's previous rate case (45.35%) is selective, result-oriented, and inconsistent with the evidence of the amount of lobbying activities associated with the EEI dues in this case. The rates provided in LG&E's Data Response to PSC 3-31 should be used on each related dues amount. The rate provided in previous rates cases was provided by EEI and was from a detail of expenses by NARUC category for core dues activities; however, this detail is no longer provided by EEI. EEI determined that most of its member companies were only interested in determining the Legislative Advocacy percentage, so beginning in 2007, EEI distributes a lobbying letter to members needing information for tax and rate case purposes. This is the letter from which the rates mentioned above by the Company and included in LG&E's Data Response to PSC 3-31 were identified. More importantly, when asked in PSC Data Request 1-7 to the AG, Mr. Henkes could not provide any good reason for basing his proposed adjustment on the percentage used five years ago in LG&E's previous rate case.

AGA Dues

Q. Do you agree with Mr. Henkes' adjustment to remove a portion of the American Gas Association dues from LG&E's test year gas operation expenses?

A. No. Mr. Henkes refers back to the Company's response to Post Hearing Question No. 11 in the last rate case, Case Nos. 2003-00433 and 2003-00434. This post hearing data request did show the breakout of the Public Affairs expense category, which was 22.59% of the dues, however, only 2.28% related to lobbying expenses. Also included in the response mentioned by Mr. Henkes was a document from the AGA entitled "Calculation of Lobbying Expenses Pursuant to Internal Revenue Code Section 162(e)". This document clearly indicates that 2.28% of the total membership dues were related to lobbying expenses and that 20.31% of the 22.59% of the dues related to Public Affairs do not relate to lobbying expenses. Similar information was used to support this case in the Company's Data Response to AG-1-73, in which it was stated that only 2.9% of the expenses relate to lobbying expenses. Therefore, the percentage used by Mr. Henkes is inconsistent with the evidence presented by LG&E in the prior rate case, as well as in this case. More importantly, when asked in PSC Data Request 1-8 to the AG, Mr. Henkes could not provide any good reason for basing his proposed adjustment on the percentage used five years ago in LG&E's previous rate case.

Manufacturers' Gas Plant Amortization Expense

Q. Do you agree with Mr. Henkes' recommendation to remove the manufacturers' gas plant amortization expense?

A. No. It is not appropriate to disallow this cost simply because the amortization period expires as of September 30, 2008. This recommendation is completely contrary to the Commission's determination to allow a three-year amortization period in LG&E's prior rate case and ignores the fact that LG&E is not recovering a return on this unamortized balance. The AG's proposed re-amortization of the balance over another three-year period further delays the recovery of the cost, thereby extending the period for which there is no carrying charge. This adjustment would simply be result-oriented, which is not appropriate and ignores other changes that have occurred after the test period ending April 30, 2008 in LG&E's gas operations. There is no historical precedent for making such an adjustment. Adjustments are typically made for known and measurable items within the test year.

To the extent that the new base rates include $81,000 in expenses that will no longer occur after September 2008, this amount of the cost of providing service will be available to offset the amounts not included in new base rates, such as a return on the additional amount of Construction Work in Progress and Plant In-Service or other increases in the cost of providing gas service. LG&E's gas operations continue to make substantial investments in the replacement of old, and the extension of new, gas distribution mains and lines to serve customers. Through November 2008, LG&E's gas operations has incurred an additional $30.9 million in Plant In-Service and Construction Work in Progress since the end of the April 2008 test year.

Also, based on information obtained in November 2008 from the Company's actuary, Mercer, LG&E is already aware that pension costs in 2009 are expected to significantly exceed those of 2008 by approximately $15.8 million as indicated in the table below.

LOUISVILLE GAS & ELECTRIC COMPANY Total annual costs of Pensions for Test Year vs. Estimated 2009		
	Test Year	**Est. 2009**
	Total Louisville Gas & Electric	**Total Louisville Gas & Electric**
Service Costs	$ 7,837,601	$ 6,868,000
Interest Costs	31,335,616	32,683,500
Return on Assets	(37,350,415)	(25,120,600)
Amortization of Prior Service Cost	6,800,631	6,652,500
Gains	1,525,716	9,299,900
Totals	**$ 10,149,149**	**$ 30,383,300**
Amount Capitalized	**$ 2,229,414**	**$ 6,708,712**
Amount Expensed	**$ 7,919,735**	**$ 23,674,588**

Note: These are estimated 2009 Pension expense numbers, and are based on Pension Asset values as of 11/30/08, using the allocations of Servco costs and capitalize vs. expense ratio used in the test year.

Miscellaneous Expense Adjustments

Q. Please comment on the miscellaneous expense adjustments proposed by Mr. Henkes for LG&E's electric and gas operations.

A. LG&E accepts the miscellaneous expense adjustments proposed by Mr. Henkes of $90,000 in expense adjustments from the calculation of the electric revenue requirement and $17,000 in miscellaneous expense adjustments from the calculation of the gas revenue requirement.

Outside Labor Expenses

Q. Please comment on Mr. Henkes' suggestion that if the Company cannot adequately prove why the high test year outside labor expenses should reasonably be considered annually recurring, the Commission should calculate and reflect a reasonable outside labor expense normalization adjustment.

A. The fact that Mr. Henkes merely raises the issue that outside labor expenses appear higher in the test year is not sufficient to overcome the long standing regulatory presumption that LG&E's expenses are reasonable and incurred in good faith A more specific and supportable challenge is required before the outside labor expenses can be validly contested as being unreasonable. The absence of any evidence that the outside operations and maintenance ("O&M") labor expenses are unreasonable suggests the reason why Mr. Henkes can only offer such a speculative recommendation.

The Commission and the Company have historically not used normalization of O&M expenses, with limited exception, such as for storm damages and injuries and damages. There is no historical precedent for normalizing outside labor expenses. Mr. Henkes's proposed recommendation is very selective and result-oriented. This is so because, if it is reasonable to allow normalization for expenses that are viewed to be too high, normalization should be allowed on expenses that are viewed to be too low in the test year. The result would be a series of selective adjustments the purpose of which would be try to offset one another for the benefit of either the customer or the shareholder. Also, simple averaging of an arbitrary number of years' expenses is more susceptible to manipulation (primarily by using a result-oriented number of years in the averaging) than the more sophisticated statistical method LG&E employs for its proposed weather normalization adjustment, and for that reason simple averaging typically is not favored. For these good reasons the Commission has declined to allow such selective adjustments in the past. Approval of this proposed adjustment would be a significant change to the historical and established rate case process.

Notwithstanding these concerns, the Company believes the outside labor expenses included in the rate case to be reasonable and recurring expenses. Mr. Henkes referred to several data responses provided by LG&E regarding outside labor expenses, including LG&E's Data Response to AG 2-22 related to outside labor – other, LG&E's Data Response to PSC 2-99 related to maintenance contracts and LG&E's Data Response to PSC 3-15 related to maintenance of boiler plant. The majority of the variances in these costs over the past several years are related to unit overhauls. Cane Run Unit 5 had a major overhaul during the test year, and this type of overhaul is only completed once every five to seven years. There were also variances due to the timing and scope of annual outages on several units. The length and scope of the outages on each unit vary depending on the run time of the units and other factors that impact unit wear. In the test year there were more outages that were longer and at a higher cost than in the previous years due to the rotational basis of the outages. These types of outages and associated expenses will continue across the LG&E fleet of generating assets.

Another significant reason for increases in the outside labor costs are related to the wages for skilled craft labor. According to the information by Fluor

Corporation (the construction contractor on the TC2 project), the market wage rates for skilled craft labor have been steadily increasing. The market wage rates increased at an annual rate of 13.9% between August 2006 and August 2007. More recently, market wages have continued to increase, but at a somewhat slower rate. The March 2008 average wage was 8.2% higher than the March 2007 average. As some larger projects begin to mobilize in the Texas/Gulf Coast/Southeast region in late 2008 and early 2009 (which is the market from which LG&E typically obtains the majority of its skilled craft labor), the additional market demand for skilled craft labor is widely expected to fuel more aggressive wage escalation than the 8%-10% pace that has occurred since about August 2007, possibly around 11%-12% or higher during the first half of 2009.

All of these factors led to the increases in outside labor during the test year The outages and overhauls of the units are cyclical and represent normal ongoing costs of maintaining the units. In addition to increases due to changes in the market for construction work, it is also normal to have inflationary increases from year to year. Thus these costs represent normal ongoing costs of operating the business.

Because the expenses incurred in the test year were reasonable and ongoing, these costs should be allowed in the rate case. An effort to normalize these expenses is simply one more attempt to make a selective, result-oriented adjustment to the case.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says she is the Director of Utility Accounting and Reporting for Louisville Gas and Electric Company, that she has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Shannon L. Charnas
SHANNON L. CHARNAS

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of December, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:
November 9, 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	))))	CASE NO. 2008-00252

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	CASE NO. 2007-00564

REBUTTAL TESTIMONY OF LONNIE E. BELLAR VICE PRESIDENT OF STATE REGULATION AND RATES LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: December 19, 2008

Q. Please state your name, position and business address.

A. My name is Lonnie E. Bellar. I am the Vice President of State Regulation and Rates for Louisville Gas and Electric Company ("LG&E" or "the Company") and an employee of E.ON U.S. Services, Inc., which provides services to LG&E and Kentucky Utilities Company ("KU"). My business address is 220 West Main Street, Louisville, Kentucky.

Q. What are the purposes of your rebuttal testimony?

A. The purposes of my testimony are: (1) to respond to the testimony of Robert J. Henkes, witness for the Attorney General, concerning LG&E's proposed unbilled revenues pro forma adjustment to operating income; and (2) to address the concerns expressed in the testimony of the low-income customer advocates.

<u>Unbilled Revenues Adjustment</u>

Q. What is the fault in Mr. Henkes's assertion that LG&E's unbilled revenues adjustment is overstated because it contains unbilled DSM, FAC, and ECR surcharge revenues?

A. Mr. Henkes errs by failing to recognize that the unbilled components of DSM, FAC, and ECR surcharge revenues are fully removed in LG&E's test year. To fully eliminate these separate mechanisms, LG&E has eliminated billed revenues for these mechanisms on Reference Schedules 1.10, 1.05, and 1.03. The amounts accrued were eliminated on Reference Schedule 1.09. The unbilled portion was removed in Reference Schedule 1.00.[1]

Generally, there are six reasons the unbilled revenues adjustment is proper and should be kept in the form in which LG&E filed it. First, the Commission has

[1] LG&E Response to AG's First DR No. 23(h).

approved this type of adjustment in LG&E's rate cases for at least the last three rate cases prior to this case and in KU's most recent rate case.

Second, the adjustment provides 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.

Third, unbilled revenues are estimates that attempt to put revenue on a calendar month basis instead of a billing cycle basis. As a result, there are no class billing determinants associated with unbilled revenues. The only metered billing determinants available are associated with as-billed revenue. With a historical test year, rate case revenue, allocators, and billing determinants should be based on known and measured metered information that is readily available and verifiable, and much more accurate than estimated unbilled revenues data.

Fourth, the billing determinants used to develop the proposed rates do not include units related to the unbilled revenues. In other words, the billing determinants used to determine proposed rates reflect as billed determinants, and do not include unbilled determinants. Consequently, if unbilled revenues are not removed from test-year operating revenues, then the billing units used to establish rates in the case would need to be revised to also reflect unbilled revenue.

Fifth, if unbilled revenues are not removed from operating revenues, all revenue adjustments would have to be re-determined on an unbilled basis and not an as-billed basis.

Sixth, for a fully normalized test year, there would be no difference between as-billed revenues and revenues including unbilled revenues.[2]

[2] LG&E Response to KIUC Second DR No. 4(b).

Low-Income Customers' Concerns

Q. What is the source of low-income customers' concerns, as explained by their advocates in this proceeding?

A. In addition to general cost of living increases, the chief reason the low-income advocates have cited in this proceeding as being their concern about the Company's proposed rate increase is that community action agencies have not had the funding they desire to serve those in need. As witness Kip Bowmar observed, "For the first time in fifteen years, every Community Action Agency in the state expended 100% of their LIHEAP [the federal Low Income Heating Energy Assistance Program] funds before the end of February. More than 50% of the agencies' LIHEAP programs in the state were closed by the first week of February."[3] LIHEAP, which provides the bulk of the funds community action agencies use to help low-income utility customers, is a federal program; neither the Company nor the Commission has any control over such funds.

Q. Please describe the recent significant LIHEAP funding increases for low-income customers in Kentucky.

A. A recent press release from Governor Beshear's office states that LIHEAP funding will more than double from the levels expected in 2009, from approximately $30 million to over $68 million.[4] This should greatly alleviate the funding concerns the low-income advocates have identified in this proceeding; indeed, the governor's press release states:

> The increase in funding is significant considering the escalation of energy prices and the number of families in need who did not receive assistance in the past. Last year, LIHEAP funds

[3] Testimony of Thomas "Kip" Bowmar on Behalf of CAK at 5.
[4] http://governor.ky.gov/pressrelease.htm?PostingGUID=%7B3077D119-DA26-4165-894A-885CDF9A3DF1%7D

> were distributed to nearly 174,000 Kentucky families. According to CHFS, an estimated 45,000 additional families needed help, but no funds remained in the program. With the increase in funding, it is estimated that up to 150,000 additional families will benefit from the assistance.

This more-than-doubling of LIHEAP funds in Kentucky for 2009 should assist in addressing the low-income advocates' concerns. Indeed, the Community Action Council, Inc. stated in one of its discovery responses that the additional LIHEAP funds coming in 2009 will enable the LIHEAP program to serve 250,000 households.[5]

Q. Particularly in view of the significant increase in 2009 LIHEAP funding, what is LG&E's response to Community Action Kentucky, Inc.'s proposal to increase the Home Energy Assistance surcharge from $.10/month per electric or gas meter to $.25/month per electric or gas meter?

A. LG&E cannot support increasing the Home Energy Assistance ("HEA") surcharge. This is particularly true given the significant LIHEAP funding increase; the proposed more-than-doubling of the HEA surcharge for both LG&E and KU would increase HEA funding by only approximately $1.9 million,[6] which pales in comparison to the over $38 million increase in LIHEAP funding for 2009. Moreover, although LG&E sympathizes with the difficulties its low-income customers face, it is LG&E's position that, generally speaking, it is the role of governments, not utilities, to collect and distribute what are effectively taxes; the LIHEAP program is a good example of government doing what it should in that regard. The relevant Kentucky statutory provisions, KRS 278.285(1) & (4), are in accord, providing that the Commission may

[5] Case No. 2008-00252, Response of the Community Action Council, Inc. to Commission Staff DR No. 1 (Dec. 4, 2008).
[6] Testimony of Thomas "Kip" Bowmar on Behalf of CAK at 6.

approve HEA programs that utilities propose, but without authorizing the Commission to approve such programs proposed by others.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says he is the Vice President of State Regulation and Rates for Louisville Gas and Electric Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

LONNIE E. BELLAR

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of December, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE AN ADJUSTMENT OF ITS ELECTRIC AND AND GAS BASE RATES	))))	**CASE NO. 2008-00252**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	**CASE NO. 2007-00564**

REBUTTAL TESTIMONY OF
JOHN J. SPANOS

ON BEHALF OF
LOUISVILLE GAS AND ELECTRIC COMPANY

FILED: December 19, 2008

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. No, but I previously submitted direct and rebuttal testimony as part of the related application for Louisville Gas and Electric Company, Case No. 2007-00564 and the related application for Kentucky Utilities, Case No. 2007-00565.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of this testimony is to rebut the pre-filed direct testimony of Attorney General Witnesses, Mr. Michael J. Majoros, Jr., and Robert J. Henkes, as well as Kentucky Industrial Utility Customers, Inc. witness, Lane Kollen.

Q. WHAT IS THE SUBJECT OF YOUR REBUTTAL TESTIMONY?

A. The first subject of my rebuttal testimony is the use of the Equal Life Group (ELG) procedure in calculating depreciation accrual rates for all asset classes for Louisville Gas and Electric Company. I will also address the discussion related to cost of removal.

Q. CAN YOU SUMMARIZE YOUR POSITION IN THE LOUISVILLE GAS AND ELECTRIC COMPANY, CASE NO. 2007-00564?

A. The depreciation accrual rates in those cases are the same depreciation rates applied in this proceeding. The depreciation rates were calculated using the ELG procedure because it is the most accurate procedure for matching capital recovery to utilization or consumption of the assets. Additionally, the accrual rates are calculated with a component of net salvage. The net salvage percent for each account is determined consistently with almost every other utility in the United States and Canada. It is known as the straight line accrual approach as the estimated net salvage costs are recovered equally over the life of the asset. Some view this as the traditional approach.

Q. CAN YOU SUMMARIZE THE KEY POINTS ON DEPRECIATION AS DESCRIBED IN CASE NO. 2007-00564?

A. There are two major issues related to depreciation. The first is the development of depreciation rates using the ELG procedure versus the Average Service Life (ASL) procedure. The second issue relates to the net salvage component of the depreciation rate. The Company proposal utilizes the traditional straight line accrual approach while Messrs. Majoros and Kollen recommend the present value method. The traditional straight line approach is utilized by all utilities in Kentucky, Virginia and Tennessee, as well as almost every utility across the United States and Canada.

Q. CAN YOU REVIEW THE CONCEPTS OF THE ELG PROCEDURE?

A. Yes I can.

Q. PLEASE DESCRIBE THE EQUAL LIFE GROUP PROCEDURE.

A. In the ELG procedure, the property group or account is subdivided into groups of equal life based on the estimated survivor characteristics of the account. The depreciation for each equal life group is based on the straight line method, that is, an equal amount of the group's service value is recorded as depreciation in each year of service. The total depreciation for the account is the summation of the depreciation for each equal life group. For this reason, this procedure is also known as the unit summation procedure.

Q. CAN YOU SHOW IN A SIMPLE EXAMPLE HOW THE EQUAL LIFE GROUP PROCEDURE COMPARES TO THE AVERAGE SERVICE LIFE PROCEDURE?

A. I will use a two unit example to show how the ELG procedure more appropriately matches recovery to consumption. Each unit costs $1,000. Unit A will be in service for 5 years and Unit B will be in service for 15 years. There is no net salvage anticipated for these units.

If depreciation is determined using the ASL Procedure, then it would be determined that the average service life for the two units is 10 years ((5 + 15)/2) and the depreciation rate is 10% (1/10 years). Therefore, the total account original cost is $2,000 and the annual depreciation amount is $200 ($2,000 times 10%). At the end of year 5, the total annual accrual for the account is $1,000 (200 times 5). Also affecting the accumulated depreciation is the retirement of Unit A for $1,000. Thus, the accumulated depreciation for the account at the end of year 5 is zero ($1,000 annual accruals minus $1,000 retirements). At the beginning of year 6, we have $1,000 of original cost, an accumulated depreciation level of $0 and one unit that has one-third of its service life expired. With the ASL procedure, the 10% rate or $100 of annual expense is booked for years 6 through 15 and at the end of year 15 we retire Unit B. We collected $1,000 in annual accruals during years 6 through 15 and made a retirement of $1,000 at year 15, so our original cost and accumulated depreciation are both zero, so full recovery was achieved. However, if we focus on the end of year 5, we had one unit remaining with two-thirds of its life expectancy still to be consumed, but 100% of the investment to be recovered. This method did not match recovery to consumption in the most appropriate manner.

In contrast, if depreciation is determined using the ELG procedure, then the depreciation expense would be recorded quite differently. I will use the same two unit example to illustrate the ELG calculation. Unit A will be in service for 5 years, therefore it will have a 20% (100 divided by 5 years) rate. Unit B will be in service for 15 years, and will have a 6.67% (100 divided by 15 years) rate. Consequently, depreciation expense for years 1 through 5 would be $200 ($1,000 times 20%) for Unit A and $66.67 ($1,000 times 6.67%) for Unit B. At the end of year 5, the total annual accruals would be approximately $1,334 ($1,000 for Unit A and $334 for Unit B). Unit A would be retired at the end of year 5, so the accumulated depreciation at the end of year 5 is $334 ($1,334 of annual accruals minus $1,000 retirement). In years 6 through 15, the annual accruals would be $66.67 for a total to $666 for the 10-year period. Thus, at the end of year 15, the accumulated depreciation is $0 ($1,000 of accruals minus the $1,000 retirement of Unit B), so full recovery was once again achieved. However, if we look back at the end of year 5, we can see recovery of Unit A matched consumption of Unit A at the time the unit went out of service, and more importantly Unit B has survived one-third of its expected life and recovery was one-third ($334/$1,000) of the expected recovery. A much more appropriate recovery pattern is recorded using the ELG procedure.

This two unit example is used to understand the recovery patterns of the two procedures; however, there are many historical transactions that affect the rate of each of these procedures that complicates the depreciation rate for each account. The following table sets forth the activity for the accumulated depreciation using the two methodologies.

COMPARISON OF ACCUMULATED DEPRECIATION
AND ANNUAL ACCRUALS USING THE
ASL VS ELG PROCEDURES

		ASL			ELG		
Year	Plant Balance	Annual* Accruals	Retirements	Accum. Depr. Balance	Annual** Accruals	Retirements	Accum. Depr. Balance
1	2,000	200	0	200	267	0	267
2	2,000	200	0	400	267	0	534
3	2,000	200	0	600	266	0	800
4	2,000	200	0	800	267	0	1,067
5	2,000	200	1,000	0	267	1,000	334
6	1,000	100	0	100	66	0	400
7	1,000	100	0	200	67	0	467
8	1,000	100	0	300	67	0	534
9	1,000	100	0	400	66	0	600
10	1,000	100	0	500	67	0	667
11	1,000	100	0	600	67	0	734
12	1,000	100	0	700	66	0	800
13	1,000	100	0	800	67	0	867
14	1,000	100	0	900	67	0	934
15	1,000	100	1,000	0	66	1,000	0

* Annual Accruals = Plant Balance Multiplied by Rate (10%)
** Annual Accruals = Plant Balance Multiplied by Rate for Each Unit

Q. DOES KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. WITNESS, LANE KOLLEN, DISCUSS THE ELG PROCEDURE?

A. Yes he does, on pages 23 through 27 of his direct testimony.

Q. CAN YOU SUMMARIZE SOME OF MR. KOLLEN'S COMMENTS WITH RESPECT TO THE ELG PROCEDURE?

A. Mr. Kollen has two main criticisms of the ELG procedure. His first comments relate to his perceived notion of accelerated depreciation when using the ELG procedure. The second issue is the perception that ELG developed rates need to be reset more often than ASL developed depreciation rates and they are less accurate.

Q. ARE ELG DEVELOPED DEPRECIATION RATES ACCELERATED?

A. No, they are not. As described in my rebuttal testimony on pages 2 through 5, as well as in Mr. Kollen's testimony, pages 24 and 25, the ELG is not accelerated but a more precise straight line approach. Although not his intent, Mr. Kollen, on page 24, line 16 through page 25, line 6 of his testimony, sets forth the depreciation recovery of each of the five equal life groups over their individual service lives which is the intent of depreciation. Each asset renders service for 1, 2, 3, 4 or 5 years and the depreciation of each asset is matched exactly to the amount of time the asset was in service. For example, the asset that survives 3 years has a recovery of $3,333 or one-third of its investment each year, and the asset that survives 4 years has a recovery of $2,500, or one-quarter of its investment each year. This more precise asset calculation is clearly straight line, not accelerated and is a more precise asset by asset recovery to asset consumption. In contrast, the average service life does not match recovery to consumption nearly as well. I will once again use Mr. Kollen's example on page 25, lines 11 through 15, to illustrate the point. In his example using the ASL (which he calls ALG) procedure, the average life is 2.5 years so the recovery of the $50,000 investment should be at $25,000 after 2.5 years if the ASL procedure properly matches recovery to consumption of the asset. Using Mr. Kollen's numbers, depreciation expense after 2.5 years would be $18,000 in year one, $14,000 in year two and $5,000 for the first half of year three, for a total of $37,000. Then we must include the retirements in the first 2.5 years to the $25,000 ($10,000 in year one, $10,000 in year two and $5,000 for the first half of year three). Consequently, the depreciation reserve at year 2.5 is $12,000 ($37,000 – $25,000) which is only 48%

($12,000/$25,000) of the surviving plant investment. Thus, in the final 2.5 years or 50% of the asset life, the ASL procedure requires 52% of the recovery.

This example isolates the five units presented by Mr. Kollen and does not include the replacement assets that would be installed each year and the smoothing affect of the yearly rates shown by Mr. Kollen on page 25 of his testimony. Additionally, Mr. Kollen does not present the comparable rates using the ASL procedure in the same fashion as is illustrated in his testimony for the ELG procedure. The ASL rates in his example would also produce higher percentages in year 1 than year 5.

Although his example is simplified, it illustrates that the ELG procedure properly matches capital recovery to asset consumption and the ASL procedure actually recovers more after the midpoint of the asset's life. In addition, neither calculation is more complex when utilizing the electronic media today.

Q. IS THERE A NEED TO RESET ELG DEVELOPED RATES MORE OFTEN THAN ASL DEVELOPED RATES?

A. No, there is not. The ideal scenario, in terms of depreciation accuracy, would be to conduct depreciation studies every year, however, that is not cost effective and tremendously burdensome for everyone. However, it is important to review rates every 3 to 5 years, regardless of the procedure, because rates will change based on service lives, net salvage percents, plant activity and plant to reserve ratios. Consequently, making the assumption that ASL rates are more stable than ELG rates is only true, if the combination of service lives and net salvage percents are stable, the plant additions and retirements are consistent each year and the reserve levels increase at the same ratio as the plant balances increase by vintage. These are assumptions that do not occur from year to year. The bottom line is the ELG developed rates are more accurate in matching recovery to consumption, the potential inaccuracies in estimation are evident in either procedure, each generation of customers is paying the appropriate amount for the assets while in service and full recovery is obtained during the life of the asset.

NET SALVAGE FOR ACCOUNTS

Q. CAN YOU DISCUSS THE ISSUE RELATED TO NET SALVAGE OR SPECIFICALLY COST OF REMOVAL?

A. Yes, I can. Both Mr. Kollen and Mr. Henkes adopt Mr. Majoros' recommendation with regard to net salvage. In other words, they propose a drastic change from the traditionally accepted method of this Commission as well as the accepted method of almost all other Commissions and regulatory bodies. The emphasis of the change is to apply financial reporting rules to regulatory recovery instead of using the previously established sound ratemaking practices. These recommendations of Mr. Majoros have been continually rejected for this improper application as well as the fact that it causes unnecessary burden on future customers in order to benefit today's ratepayers. Mr. Majoros' methods backload recovery and are intended only to lower depreciation.

Q. CAN YOU SUMMARIZE YOUR DISCUSSION OF NET SALVAGE FROM CASE NO. 2007-00564?

A. Yes.

Q. WHAT ARE NET SALVAGE AND NEGATIVE NET SALVAGE?

A. Net salvage is the gross salvage value of retired property less the cost of removal of such property. If cost of removal exceeds salvage value, the net salvage is negative, hence, negative net salvage.

Q. WHAT IS MR. MAJOROS' PROPOSAL FOR NET SALVAGE THAT IS FOLLOWED BY MR. HENKES AND MR. KOLLEN?

A. He has proposed a radical change in the basis for determining the Company's allowance for net salvage for all accounts for Louisville Gas and Electric Company. His proposal is that net salvage should be discounted to a present value level for determining the calculation of depreciation.

Q. HAS MR. MAJOROS CONSISTENTLY MADE THIS PROPOSAL FOR CHANGING NET SALVAGE PERCENTS FROM THOSE PROPOSED BY MR. SPANOS?

A. No, he has not. Mr. Majoros continually makes different proposals to adjust net salvage percents, seemingly with the single motive of reducing depreciation expense not just proper recovery. As can be seen in past cases in Kentucky alone, he switches from the cash basis proposal to the present value proposal to a normalization proposal. None of these proposals are designed to accomplish the definition of depreciation which is recovery of the full service value of the assets during the life of the asset in a rational manner, which is the basis of my traditional proposal. Depreciation is not intended to be a result oriented calculation, yet Mr. Majoros continually changes his approaches in order to achieve the result of reducing depreciation.

Q. DO AUTHORITATIVE TEXTS ON DEPRECIATION SUPPORT YOUR PROPOSAL RELATED TO NET SALVAGE?

A. All authoritative texts on the subject of depreciation support my proposal to accrue for net salvage in the traditional manner presented in my study. The two depreciation texts most often cited by depreciation experts as authoritative support the traditional approach that I have proposed. Public Utility Depreciation Practices, published in 1996 by the National Association of Regulatory Utility Commissioners states:

> Closely associated with this reasoning are the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.[1]

Depreciation Systems, another widely accepted text states the concept in this manner:

> The matching principle specifies that all costs incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring of an asset currently in service must be accrued and allocated as part of the current expenses.[2]

Q. WHAT TREATMENT OF NET SALVAGE DO YOU PROPOSE?

A. I propose, consistent with the authoritative texts and the policy of the very large majority of regulatory commissions, the traditional incorporation of net salvage in the determination of depreciation. The traditional approach has been used by this Commission in establishing the Company's ratemaking allowances for depreciation for decades. The traditional approach collects net salvage costs ratably over the life of plant from the customers served by the plant. This approach is equitable and conforms to the definition of depreciation as the loss in service value, where service value is the difference between original cost and net salvage.

Q. YOU STATED THAT IT IS MORE APPROPRIATE AND EQUITABLE TO RECOGNIZE NET SALVAGE COSTS DURING THE LIFE OF THE RELATED PLANT. PLEASE EXPLAIN.

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1 Public Utility Depreciation Practices. Page 157. National Association of Regulatory Utility Commissioners. 1996.

2 Depreciation Systems, Wolf, Frank K. and W. Chester Fitch. Page 7. Iowa State University Press. 1994.

A. The net salvage cost of an item of plant is a part of its service value and, therefore, it is a part of the item's cost of providing service. The cost of the item providing service should be collected from the customers that receive the service. Thus, an allocable portion of the net salvage cost should be recovered each year from the customers receiving the value of the service rendered by the item of plant in the same way that an allocable portion of the item's original cost is recovered from such customers each year. This approach is equitable in that customers are responsible for the costs of plant that provide service to them. This is a sound ratemaking principle. This concept does not include the notion of also discounting to present value the future recovery because the results are too high.

Q. HAVE YOU PREVIOUSLY ILLUSTRATED THIS PRINCIPLE AS IT APPLIES TO NET SALVAGE COSTS?

A. Yes, I have. There is a simple example on page 10, line 16, through page 12, line 1 of my rebuttal testimony for Case No. 2007-00564.

Q. WHAT WERE THE STATISTICAL BASES FOR YOUR NET SALVAGE ESTIMATES?

A. The statistical bases for my estimates of net salvage were the historical net salvage costs as a percent of the original cost of the retired assets that produced the gross salvage or the required costs to remove.

Q. DOES THE USE OF THESE STATISTICAL BASES RESULT IN THE COLLECTION OF FUTURE INFLATED REMOVAL COSTS FROM CURRENT CUSTOMERS?

A. Yes, to a certain extent. The reliance on historical indications of net salvage as a percent of the original cost retired will result in the collection of net salvage costs at a future price level. However, such reliance also assumes that there will be substantial improvements in technology, comparable or lesser environmental regulations and a significant reduction in inflation.

Q. DOES THE USE OF NET SALVAGE PERCENTS THAT ARE COMPARABLE TO THE HISTORICAL INDICATIONS ASSUME THESE EVENTS?

A. Yes. The net salvage percents, which are the net salvage costs divided by the original costs of the assets that have been retired and expressed as percents, are related to the retirement of plant that on average is significantly younger than the average service life of the plant in service, on an original cost dollar weighted basis. For example, the average age of retirements of distribution poles during the most recent 20 years, 1988-2007, is approximately 30 years. This is less than the average life of 50 years estimated for this account.

The average net salvage percent related to these retirements, made on average at age 30, was negative 60 percent. That is, after 30 years in service, the plant was retired and the cost to remove the plant, as a result of inflation, technological changes and other factors, was 60 percent of the cost to install the same plant.

The future retirements of the total current distribution poles in service will have an average age that actually exceeds the average life. Thus, future retirements will be of plant that has been in service nearly one and one-half times as long as the plant retired during the period 1988-2007. For retirements at such ages to experience net salvage that is 60 percent of the cost to install, there will have to be a reduction in the rate of inflation adjusted for technological improvements. If the rate of inflation adjusted for technological improvements that occurred between the installation and retirement of plant retired during the period 1988-2007 occurred over a period that is one and one-half times as long, the net salvage cost would be much greater as a percent of the original cost of the plant retired.

Q. WHAT IS THE IMPLICATION OF THE ASSUMPTION THAT THE FUTURE RATE OF INFLATION ADJUSTED FOR TECHNOLOGICAL IMPROVEMENTS WILL BE LESS THAN THE HISTORICAL RATE?

A. The implication of this assumption as reflected in my estimates of net salvage percents is that the resultant net salvage accruals are most likely inadequate to recover the total net salvage costs over the entire life cycle of the plant currently in service.

Q. DO YOU HAVE ANY CONCERN THAT THE LEVEL OF NET SALVAGE COSTS INCURRED WILL BE LESS THAN THE AMOUNTS THAT YOU HAVE ESTIMATED?

A. No, I do not. Net salvage costs will be incurred. The estimates that I have made will almost certainly result in the recovery of less, not more, net salvage than the actual costs incurred.

Q. IS IT APPROPRIATE TO ASK CURRENT CUSTOMERS TO PAY FOR FUTURE COSTS OF REMOVAL AT A PRICE LEVEL THAT IS GREATER THAN TODAY'S PRICE LEVEL?

A. Yes, it is. The future cost to remove an item of plant is part of the service value that it renders to current customers and a ratable portion of such costs should be recovered from these customers. That is the theory of depreciation, i.e., the loss in service value during a specific period. As these future costs are recovered from current customers, they are deducted from rate base. This deduction in the amount on which the utility is entitled to earn a fair return, in effect, represents an amount on which the customer earns a return or otherwise stated the utility reduces its requirement for return. That is, as customers provide for the future cost of removal, they receive a return on such amounts because less rate base is required. This is fair compensation for making payment prior to the cost incurrence by the utility. Further, as already noted, by charging customers for these costs during the life of the plant; the customers that benefit from the plant, or consume its service value, are the ones who pay for such service. Customers paying today for future costs of removal and receiving a return on such payments is no different than the utility recovering today amounts that it invested many years ago, but on which it earned a return until the amount was recovered from customers.

Q. WHY ARE THE CURRENT NET SALVAGE ACCRUALS SO MUCH GREATER THAN THE CURRENT EXPERIENCE?

A. The difference in price level as described above is part of the difference. Another significant difference is that the current experience is related to plant retirements that largely come from an older plant base that was constructed to serve fewer customers, whereas the current net salvage accruals relate to the plant presently in service that serves a much larger customer base.

Q. IS IT APPROPRIATE FOR LOUISVILLE GAS AND ELECTRIC COMPANY TO COLLECT AMOUNTS FOR FUTURE NET SALVAGE COSTS THAT ARE GREATER THAN THE AMOUNTS CURRENTLY EXPENDED FOR SUCH COSTS?

A. Yes, it is. Although the amount that my study proposes to collect from customers for future net salvage costs is greater than the amount currently expended for such costs, the amount that the Company spends for plant additions is far greater than the amount that it proposes for the recovery of original cost. If net salvage accruals should be limited to discounted net salvage expenditures, then full recovery will not be achieved during the life of an asset. Thus, the amount for recovery of costs is far less than actual expenditures. Equity considerations require that customers pay for the service value, original cost less net salvage, of the plant from which they receive service. The fact that this results in accruals for net salvage that are greater than the current experience is not inappropriate.

Q. DOES MR. KOLLEN OR MR. HENKES HAVE ANY OTHER INSIGHT ON THE TOPIC OF NET SALVAGE?

A. No, they do not. Each of them adopts Mr. Majoros' approach in their calculations of depreciation expense.

Q. HAS MR. MAJOROS EXPANDED ON HIS DISCUSSION OF COST OF REMOVAL IN THIS CASE, COMPARED TO THE CASE NOS. 2007-00564 AND 2007-00565?

A. Yes, he has. In this case, he proposes to move previously accrued cost of removal from accumulated depreciation to a regulatory liability. He states the reason for this is because the amounts are not specifically recognized as regulatory liabilities for ratemaking purposes. However, he does not mention that the Company continually records the incurred cost of removal and gross salvage into the accumulated depreciation account. He also does not mention that the purpose of remaining life accrual rates insures full recovery of the service value of all assets which includes the cost of removal at end of life.

Q. WITH THE REMAINING LIFE METHOD IN PLACE, IS THERE A REASON TO MAKE THIS CHANGE?

A. No, there is not. Mr. Majoros has proposed this change before and this Commission has not accepted it. There are different regulatory and financial rules and practices that should be maintained for their intended purposes. The Statement of Financial Accounting Standard No. 143 is a financial reporting pronouncement, not a regulatory ratemaking practice, thus, it should not be applied to future depreciation practices.

Q **PLEASE SUMMARIZE YOUR TESTIMONY RELATED TO NET SALVAGE.**

A. The portion of the annual depreciation accrual rates and amounts proposed by the Company in this proceeding that is related to net salvage is reasonable and in accordance with sound ratemaking principles. Depreciation is the loss in service value and service value is the difference between original cost and net salvage value. Thus, net salvage should be a part of the straight line whole life depreciation accrual.

Net salvage costs should be recovered from customers served by the plant that results in the expenditure of net salvage costs. The use of a straight line whole life accrual over the life of the asset accomplishes this equity. The present value net salvage approach does not. It is appropriate for the net salvage accrual to exceed the current net salvage cost during a period of system growth and prior to reaching a steady state for the plant.

The estimates of net salvage percents used in developing the net salvage accrual are very reasonable and likely understate the future net salvage costs that will occur. Almost every state, including Kentucky, uses the traditional approach of straight line whole life or remaining life accrual of net salvage during the life of the asset, as I have recommended. Considerations of customer equity with regard to the matching of depreciation expense with the consumption of service value should control. The proposal to discount net salvage costs should be rejected and the traditional approach of accruing for such costs during the life of the related asset should be retained. Finally, the accrued cost of removal should be maintained in accumulated depreciation, not moved to a regulatory liability for ratemaking purposes.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) **SS:**
COUNTY OF CUMBERLAND)

The undersigned, **John J. Spanos**, being duly sworn, deposes and says that he is the Vice President, Valuation and Rate Division for Gannett Fleming, Inc., that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John J. Spanos
JOHN J. SPANOS

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 11th day of December, 2008.

(SEAL)
Notary Public

My Commission Expires:

February 20, 2011

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	))))	CASE NO. 2008-00252

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	CASE NO. 2007-00564

REBUTTAL TESTIMONY OF
WILLIAM STEVEN SEELYE
PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

Filed: December 19, 2008

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6001 Claymont Village Dr., Suite 8, Crestwood, Kentucky, 40014.

Q. Did you submit direct testimony in this proceeding?

A. Yes.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of Louisville Gas and Electric Company ("LG&E").

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut Attorney General ("AG") witness Glenn A. Watkins and Kentucky Industrial Utility Customers, Inc. ("KIUC") witness Lane Kollen concerning the electric temperature normalization adjustment. I will also rebut Mr. Watkins regarding his proposed electric and gas cost of service studies, revenue allocation, and rate design. I will also address cost of service and rate design issues raised by KIUC Witness Stephen J. Baron.

Q. How is your rebuttal testimony organized?

A. My rebuttal testimony is organized into the following sections:

I. Introduction
II. Electric Temperature Normalization - Regulatory Policy Considerations
III. Electric Temperature Normalization - Technical Considerations
IV. Electric Cost of Service Study
V. Electric Revenue Allocation and Rate Design

VI. Gas Cost of Service Study and Rate Design

II. ELECTRIC TEMPERATURE NORMALIZATION -- REGULATORY POLICY CONSIDERATIONS

Q. What is the purpose of the electric temperature normalization adjustment?

A. LG&E's electric sales vary significantly with changes in temperature. Because temperatures were significantly hotter than normal during the test year, LG&E's test-year revenues are considerably higher than what would be anticipated on a going-forward basis. Given the considerable difference between actual and normal cooling degree days during the test year, it is important to adjust revenues and expenses so that they will be representative of normal, going-forward levels when the rates are placed in effect at the end of the suspension period.

Q. Given that the Commission has been very cautious about allowing normalization adjustments, why should the Commission approve the proposed weather normalization adjustment?

A. Unlike most proposed normalization adjustment proposals, such as those advanced by Messrs. Henkes and Kollen in this proceeding, the proposed weather normalization adjustment is not result-oriented and *ad hoc*; rather, as I explained in my direct testimony and as I further explain below, the proposed weather normalization adjustment methodology identifies and applies very clear and objective measures to determine whether the variability of the data is so significant that it merits a possible temperature adjustment to revenues. It is only if these criteria are met that an adjustment is made. The rigor of the Company's proposed weather normalization methodology prevents the kind of self-serving manipulation of data that too often is part of proposed normalization adjustments.

Q. In direct testimony filed on October 28, 2008, KIUC Witness Kollen and AG Witness Watkins recommend that the electric temperature normalization adjustment should be rejected. Have they offered valid reasons for concluding that LG&E's electric revenue should not be adjusted to reflect normal temperatures?

A. No. The core of both of their arguments is that as a matter of regulatory policy and practice the Commission should not consider weather normalization for electric utilities in Kentucky. For example, the only reason that Mr. Kollen gives for claiming that weather normalized revenues are not "superior" to the use of actual revenues in a rate case proceeding is that the "Commission has rejected all prior attempts of the Companies to normalize electric revenue for temperature at least since 1972." Mr. Kollen's objection to the Company's electric temperature normalization adjustment is not methodological. He offers no comments at all on the statistical models used by LG&E to develop the temperature normalization adjustment. Other than pointing out that the Commission has never accepted an electric temperature normalization adjustment, his arguments against electric temperature normalization would apply equally to gas temperature normalization – which the Commission has always accepted. Mr. Kollen has not made a valid case against electric temperature normalization; he simply doesn't *feel* that the Commission should consider electric temperature normalization.

Mr. Watkins' argument against an electric temperature normalization is -- one might say -- a bit more nuanced. He simultaneously makes a case *for* and a case *against* temperature normalization. Ultimately, the case that Mr. Watkins makes *for* an electric temperature normalization adjustment is more persuasive and better reasoned than the case that he makes against temperature normalization. In fact, on page 10 of his direct testimony, Mr. Watkins makes the best possible case for an electric temperature normalization adjustment:

> Based on my analyses, I conclude that the overall cooling season (summer) during the test year was exceptionally warm which translated into exceptionally high summer sales for LG&E. <u>This weather (and attendant kWh sales) falls beyond what can reasonably be expected on a going-forward basis and warrants a downward adjustment.</u>
>
> (Watkins Direct Testimony, p. 10, lines 12-15. Emphasis supplied.)

The very purpose of selecting a test year and making pro-forma adjustments to test-year operating results in a rate case is to establish rates that will reasonably reflect a utility's prudently incurred costs on a going-forward basis. This principle is well established.[1] Mr. Watkins is absolutely correct that the temperatures and sales during the test year did indeed fall "beyond what can reasonably be expected on a going-forward basis." Because revenue requirements must be based on operating results that can reasonably be expected on a going-forward basis, Mr. Watkins is also absolutely correct that a downward adjustment to revenue and to expense is warranted. Inexplicably, Mr. Watkins constructs his own temperature normalization adjustment, and then makes an incontrovertible case in support of a temperature normalization adjustment, but ultimately recommends against his adjustment because of an incorrect and ultimately irrelevant belief that, "From a conceptual standpoint, the general consensus of public utility commissions throughout the United States is that it is unreasonable to weather normalize electric utility revenues for ratemaking purposes." (*Id.*, p. 3, lines 9-11.)

The *conceptual* case against electric temperature normalization as made by Mr. Kollen and Mr. Watkins has already been addressed and settled by the Commission. The Commission has repeatedly indicated that it has no *conceptual* problems with temperature normalization. For example, the Order in Case No. 98-426 states as follows:

[1] For example in *South Central Bell Telephone Company v. Louisiana Public Service Commission* [744 F2d 1107] the U.S. Court of Appeals for the Fifth Circuit, stated that, "In determining a rate structure that will adequately meet a utility's ***prospective revenue requirements***, a regulatory commission makes predictions based on the utility's revenues, expenses, and investments in some selected previous year, called a 'test year'". (Emphasis supplied.) Also, see James C. Bonbright, *Principles of Public Utility Rates*, p. 150, where the author states that, "Commission orders approving a rate-level increase or requiring a decrease are usually based on findings that, in the light of recent realized earnings, the existing rates would probably yield a deficient, or an excessive, rate of return ***in the near future***. As a guide to such a finding, a commission may first determine the return realized during some twelve-month period taken as a 'test year.' In estimating the rate of return that may

> The Commission has considered an electric weather normalization adjustment in four previous LG&E rate cases. In all four cases, the Commission denied the proposed adjustment, noting the failure of the sponsoring party to adequately support the adjustment. However, the Commission has also stated its general endorsement of the concept of normalization and is willing to consider such a proposal in future rates proceedings. We reaffirm that willingness in this Order.
>
> (Order in Case No. 98-426 dated January 7,2000, p. 73.)

The Commission's objections to prior temperature normalization adjustments have not been *conceptual*, they have been *methodological*. Mr. Kollen's reasons for recommending against temperature normalization are conceptual. While Mr. Watkins raises a number of methodological issues concerning the temperature normalization adjustment (which will be addressed later in my rebuttal testimony), his reasons for recommending against temperature normalization are also ultimately conceptual.

Q. Even though Mr. Kollen and Mr. Watkins are addressing conceptual issues that have already been settled by the Commission, please address all of their reasons for recommending against temperature normalization. First, Mr. Kollen suggests that using actual revenues is "superior" to using weather normalized revenues. Is he correct?

A. No. From a ratemaking perspective it is appropriate to develop test-year revenue and billing determinants that are representative of what would be anticipated on a going-forward basis. In a general rate case, service rates are set at a level that will provide the utility a reasonable opportunity to recover its costs on a going-forward basis,

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be earned during the next year, or during some other future period, the commission will accept convincing evidence of change in operating expenses and in other operating deductions." (Emphasis supplied.)

including a fair, just and reasonable return on investment. The underlying principle is that when the approved rates in a rate case go into effect, those rates will produce a level of revenue that will allow the utility to recover its reasonably incurred costs on a going-forward basis. This is a basic ratemaking principle. As Mr. Watkins correctly points out, there were a number of months during the test year when it was exceptionally hot. Neither Mr. Watkins nor Mr. Kollen try to argue that LG&E does not sell more kWhs when extraordinarily hot temperatures occur day after day as it was during August, September and October 2007. Based on the monthly cooling degree days, May 2007 was 68 percent hotter than normal; August 2007 was 58 percent hotter than normal; September was 77 percent hotter than normal; and October 2007 was 202 percent hotter than normal! In terms of cooling degree days, this was one of the hottest summers on record.

All that Mr. Kollen says in support of his claim that weather-normalized revenues are not "superior" to the use of actual revenues is that the Commission has traditionally rejected temperature normalization adjustments and that temperature normalization should not be performed in isolation. Both of these considerations are without merit. As I've already explained, the Commission has never rejected the concept of temperature normalization. The fact that the Commission has rejected prior temperature normalization adjustments purely on methodological grounds in no way supports an argument -- one way or the other -- that weather-normalized revenues are either "superior" or "inferior" to actual revenue. Any judgment about whether the Company's temperature-normalized revenues are representative on a going-forward basis can only be formed based on an assessment of the methodology used to normalize revenues, not based on whether the Commission has previously rejected temperature normalization adjustments in the past. The Commission rejected earlier temperature normalization adjustments because of very specific concerns about the methodologies used to develop the adjustment. To my knowledge, the Commission has never asserted that using actual revenues is "superior" to using weather-normalized revenues.

Mr. Kollen's argument that temperature normalization should be rejected because normalization adjustments should not be considered in isolation is a textbook example of flawed argumentation.[2] Specifically, he asks that we assume, without argument, that there might exist some other unspecified and unknown expenses that ought to be normalized. He then argues that the Company's temperature normalization adjustment – which has been properly identified and statistically validated – should be rejected because these hypothetical revenue or expense items which he has failed to identify might also need to be normalized.

As I stated above, however, unlike most proposed normalization adjustment proposals, such as those advanced by Messrs. Henkes and Kollen in this proceeding, the proposed weather normalization adjustment is not result-oriented and ad hoc; rather, the proposed weather normalization adjustment is the product of a valid and sophisticated statistical analysis. The rigor of the Company's proposed weather normalization methodology prevents the kind of self-serving manipulation of data that too often is part of proposed normalization adjustments.

Furthermore, I agree that a temperature normalization adjustment – or any other adjustment for that matter – should not be performed in isolation, *but in what way has the Company's temperature normalization adjustment been performed in isolation*? In performing the temperature normalization adjustment, both revenues and expenses were adjusted. The Company made every effort to make all appropriate pro-forma adjustments to ensure that test-year operating results are representative on a going-forward basis. In accordance with normal rate case practice, the intervenors in this proceeding have also had every opportunity to submit data requests, review the Company's revenues and expenses, and recommend appropriate adjustments. I am quite certain that if any of the intervenors felt that a particular expense was not representative on a going-forward basis then they would have identified it through direct testimony.

Q. Although at one point in his direct testimony Mr. Watkins insists that a temperature normalization adjustment should be made, at another point he recommends against making such an adjustment. Are the reasons he gives for rejecting the temperature normalization adjustment persuasive?

A. Not at all. Throughout his testimony, he insists that "there is no doubt that weather, primarily temperature, effects [sic] energy usage." He goes on to explain that:

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[2] Mr. Kollen's argument is an example of a logical fallacy often referred to as *petitio principii*

> In the summer there are periods of days that are very hot and electricity sales are elevated. Similarly there are mild days throughout the summer in which electricity sales are depressed due to reduced air conditioner loads.
>
> (Watkins Direct Testimony, p. 4, lines 7-10.)

He then goes on to claim that because electric customers have energy appliances that do not vary with temperature, it is "rare for commissions to consider weather normalization for electric utilities." Although he insists later in his testimony (p. 10) that the unusually hot summer months during the test year "warrants a downward adjustment" to revenue, he recommends that "as a matter of policy, the Commission would be well guided to continue its practice of not considering weather normalization for Kentucky electric utilities." (*Id.*, p. 4.)

Q. Are electric temperature-normalization adjustments all that rare?

A. No. While I haven't performed a comprehensive survey, I am aware of a number of jurisdictions that have approved temperature normalization adjustments for electric utilities -- Connecticut, North Carolina, Washington D.C., Indiana, Georgia, Kansas, and Nevada. I suspect that there are other states that have approved temperature normalization adjustments in rate cases. I also suspect that the issue has never come up in some jurisdictions -- such as in those jurisdictions that allow forecasted test years or in jurisdictions in states that may not experience the sort of swings in heating and cooling loads that would call for a temperature normalization adjustment such as the one we are proposing here. Mr. Watkins has offered no evidence to support his claims that it is "rare for commissions to consider weather normalization" or that "the general consensus of public utility commissions throughout the United States is that it is unreasonable to weather normalize electric utility revenues for ratemaking purposes." But, as I have already mentioned, his general policy recommendation is beside the point because the Commission has already endorsed the concept of temperature normalization.

II. ELECTRIC TEMPERATURE NORMALIZATION -- TECHNICAL CONSIDERATIONS

Q. In calculating his electric temperature normalization adjustment, Mr. Watkins uses a different methodology from the one you propose for the Company. Please describe the differences between his electric temperature normalization methodology and yours.

A. In calculating his electric temperature normalization adjustment, Mr. Watkins uses a very similar -- albeit a less thorough and rigorous -- methodology. The following are the principal differences between his methodology and ours:

First, Mr. Watkins' methodology only utilizes HDD65 and CDD65 as the weather variables. The Company performs a step-wise regression analysis to select variables from an array of weather and non-weather variables. Mr. Watkins' model is reduced to include only HDD65 during the winter months and CDD65 during the summer months. He does not perform a step-wise regression analysis. I will explain below why step-wise regression was utilized.

Second, Mr. Watkins recommends that "banding should be applied separately to the entire heating season and again for the entire cooling season." (Id., p. 8.) Under the Company's methodology, a banding methodology is performed monthly. Specifically, under LG&E's methodology each month is analyzed, and if the actual temperature values during the month fall outside of a two standard deviation band width (determined as one standard deviation above the average and one standard deviation below the average) then a normalization adjustment is made for the applicable temperature variable. But if the actual temperature value for the month falls inside the bandwidth, then no adjustment is made. Therefore, under LG&E's methodology banding is performed monthly; whereas, with Mr. Watkins' approach, banding would be performed on a seasonal basis. Under Mr. Watsons' approach, the regression coefficients would also be determined seasonally rather than monthly. I will explain below why it is appropriate to perform parameter estimation and banding on a monthly basis.

Third, Mr. Watkins removes April, May and October from his temperature normalization analysis and LG&E does not. I will explain below why these months should not be removed.

Q. Do you have any objections to simplifying the model and only using HDD65 and CDD65?

A. No. The principal reason that LG&E proposed the methodology that was submitted in this proceeding was to make certain that all of the concerns identified in prior Commission orders were adequately addressed. The methodology that we proposed is rigorous, statistically sound, and fully addresses the concerns raised by the Commission concerning previous temperature normalization adjustments submitted in rate case proceedings. Although it is a statistically sound approach, the process proposed by the Company involves a significant number of steps that cannot be performed readily using a basic spreadsheet package such as Excel. In statistical and mathematical modeling there is often a tradeoff between developing the most accurate model and developing a more simplified methodology that yields reasonable results but is easier to work with. In order to address criticisms raised in the Commission's Order in Case No. 10064, the Company wanted to make sure that an array of weather and non-weather variables were considered in the analysis. In its Order in Case No. 10064, dated July 1, 1988, one of the reasons given for rejecting the temperature normalization adjustments was that only one variable was considered in the analysis. (Order, Case No. 10064, p. 45). The objective of including more than one variable resulted in the adoption of a step-wise regression procedure to select variables that proved to be statistically significant and to eliminate those that did not prove to be statistically significant. But, as I pointed out in my direct testimony, extreme care must be exercised in performing step-wise regression. Without performing a number of other statistical tests (which were performed as part of the Company's proposed methodology), step-wise regression can result in the selection of inappropriate variables. LG&E took great care to identify and eliminate potentially problematic variables. *Limiting the temperature variables to HDD65 and CDD65* would certainly reduce the number of other tests that would have to be performed and would avoid the risk of including inappropriate variables, which we took great pains to avoid in the LG&E proposal. While reducing the number of variables will generally result in a reduction in the statistics of fit for a model (as measured, for example, by the R-square), after analyzing the results, we have determined that limiting the temperature variables to HDD65 and CDD65 (and not incorporating other temperature variables through the application of a step-wise regression procedure) will not significantly weaken the model. Therefore, the Company is willing to accept Mr. Watkins recommendation that only these two temperature variables be utilized.

Q. Even though the Company is willing to simplify the model and only use HDD65 and CDD65 instead of the other weather variables, do you agree with Mr. Watkins' assertion that the Company's electric temperature normalization model produces inconsistent results?

A. No. Mr. Watkins says that in "Mr. Seelye's attempt to be unnecessarily surgically precise, he arrives at nonsensical conclusions and models." (Watkins Direct Testimony at p. 12, lines 16-17.) I agree that the Company was trying to be extremely precise in the development of a statistically sound model. As I have indicated, we wanted to address all of the concerns raised by the Commission regarding prior temperature normalization adjustments. But I categorically reject Mr. Watkins' assertion that the Company's model produces inconsistent results. The failure is not with LG&E's model but with his misinterpretation of the multivariable regression results. In concluding that the Company's approach produces "nonsensical results" he compares the regression coefficients for a set of variables in July to the regression coefficients for an entirely different set of variables in August. Because the regression coefficient for CDD70 during July is significantly different from the regression coefficient for CDD70 during August, Mr. Watkins assumes that model is producing incorrect results. He says that, "What this means is that, *all other things constant*, kWh sales will vary by 227,194 kWh for each variation in CDD70 during July, but will vary by 512,577 in August." (Watkins Direct Testimony at p. 13, lines 2-4.) But all other things are not constant. These are models for two different months. Anyone who has done much work in modeling electric sales will know that temperature coefficients vary from month to month. But more troubling is his assumption that the coefficients for CDD70 should remain constant from July to August when the model for July includes an entirely different set of temperature variables than the ones that are included in the model for August. The purpose of multivariable regression modeling is to capture the variations in the dependent variable that can be explained by variations in the independent variables. The inclusion of more variables (or even different variables) in a model will almost always affect the parameter estimation for any given variable. Mr. Watkins claims that everything is equal when the July model is clearly not the same model as the one used for August. For July, the parameter estimate for CDD70 cannot be evaluated without also considering the parameter estimate for Maximum Temperature. Likewise, for August, the parameter estimate for CDD70 cannot be evaluated without also considering the parameter estimates for at least Minimum Temperature but also the parameter estimated for Cloudy and Weekend. At the very least, Mr. Watkins should have considered the regression coefficients for CDD70 *conjointly* with Maximum Temperature during July and the regression for CDD70 *conjointly* with Minimum Temperature during August. Without considering the conjoint effects of the variables used in the models, Mr. Watkins' analysis of the statistical results for these two months devolves into a grossly oversimplified and incorrect evaluation.

Q. **Do you agree with Mr. Watkins's recommendation that the temperature normalization adjustment should be performed by modeling and banding the entire season rather than modeling and banding each month?**

A. No. The temperature normalization adjustment should not be performed using seasonal modeling and banding. As long as the analysis encompasses the entire heating and cooling season, and therefore does not arbitrarily eliminate April, May and October, as recommended by Mr. Watkins, the results obtained from performing the adjustment seasonally are not significantly different from the results obtained when the adjustment is performed monthly. In spite of the similarity in the results, the temperature normalization adjustment should not be determined using seasonal modeling and banding. Calculating the electric temperature adjustment on a monthly basis is more consistent with the methodology approved by the Commission to determine the gas temperature normalization adjustment, which is calculated on a monthly basis, and is also more accurate. The reason that it is important to perform a monthly analysis is to avoid problems with non-linearity that can occur when performing a regression analysis across a full season. Performing the analysis across a full season can potentially create two types of non-linearity problems. First, temperature sensitive loads (kWh per degree day) will vary over a fairly wide range of temperatures. Within a relatively small range of temperatures, the response of electric sales to temperature will be practically linear, but over a wide range of temperatures, the response of sales to temperature will not be perfectly linear. Because temperatures tend to be more homogenous within a single month than over an entire season, accurate monthly models can be developed without resorting to more complicated non-linear regression techniques such as spline regression, kernel regression, or local polynomial fitting.[3] LG&E specifically developed monthly models so that we could rely on linear regression (using least squares estimation), thus avoiding the need to employ these more complicated non-linear techniques. Obviously, if the regression coefficients (load per degree day) are determined using monthly modeling, then the banding approach must also be applied monthly.

Q. Do you agree that April, May and October should be removed from the analysis?

A. Absolutely not. Although I agree that these months are often referred to as "shoulder months," this in no way suggests that there is no temperature response during these months. If it is hot in April, May or October (but especially in May or October) then LG&E's customers will use their air conditioners and thus use more electric energy. Similarly, if it is cold during any of these months (but especially in April) then customers will use space heating. The fact that temperatures tend to be more

[3] See Michael G. Schimek, ed., *Smoothing and Regression: Approaches, Computation, and Application*. (Wiley Series in Probability and Statistics: 2000) Although spline regression, kernel regression, and local polynomial fitting are all excellent techniques, they are significantly more complicated and less

moderate during these months in no way implies that deviations from normal temperatures during these months will not result in increased or decreased sales. Under the Company's proposed banding approach, if temperatures are close to normal during these months then an adjustment would not be made. An adjustment would only be made if temperatures fall outside of the two standard-deviation bandwidth during any given month *and* if there is a statistically verifiable impact of temperature on kWh sales during the month.

The sensitivity in kWh sales to variations in temperature is particularly evident during May and October of the test year. The regression models for the residential rate class produced an R-square of 0.9413 for May 2007 and an R-square of 0.9593 for October 2007. Even for April 2007, which is undoubtedly a "shoulder" month, the R-square was 0.6889. Months for which the R-squares are in excess of 0.60 – particularly May and October for which the R-squares are in excess of 0.90 – should not be eliminated simply because they are sometimes referred to as "shoulder months." The approach that the Company recommends – which is based on empirical analysis and objective inquiry rather than on preconceptions and conjecture – is to only eliminate a month if the R-square is below 0.60 or if other key model statistics are inadequate (particularly if a t-statistic for a temperature variable is less than 1.8). Using a rigorous statistical approach strongly implies that April, May, and October should not be eliminated from the analysis. Therefore, even if the Commission accepts Mr. Watkins' methodology that calculates the temperature

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standardized than linear regression modeling.

adjustment by modeling the entire cooling season and the entire heating season (rather than a month-by-month approach), then the Company strongly recommends that Mr. Watkins' approach be corrected to include May and October during the summer cooling season and April during the winter heating season.

Q. ***Are there implementation problems with Mr. Watkins' seasonal banding approach if April, May and October are included as they should be?***

A. Yes. For LG&E, banding cannot be performed on a seasonal basis if April, May and October are included in the temperature normalization adjustment. The problem with seasonal banding is that it will only produce seasonal sales adjustments. This criticism, which at first blush may seem tautological, underscores a serious problem with Mr. Watkins' methodology, especially if adjustments are made for the significant departures from normal weather experienced in May and October during the test year, as they should. LG&E's rates do not remain constant throughout the year. Specifically, Rate GS is higher during June through September than the rest of the year. Consequently, the temperature normalization adjustment cannot be calculated for Rate GS unless banding is performed on a monthly basis. In order to calculate the revenue effect of the temperature normalization adjustment the kWh amount determined from the application of the banding approach must be applied to the applicable rate. Because Rate GS is not constant throughout the year, monthly sales are needed to calculate the revenue impact. Therefore, even if the regression coefficients were determined seasonally, as proposed by Mr. Watkins, banding must be performed monthly in order to determine the kWh sales amounts to be multiplied by the appropriate energy charge during the month. Not only is seasonal banding problematic for Rate GS, the adoption of seasonal banding would complicate adoption of seasonal rate designs for other customer classes in the event that the Commission wanted to expand the use of seasonal rates at some point in the future.

Q. If the Commission prefers a less intricate methodology for calculating the temperature normalization than the one the Company proposed, what would you recommend?

A. As mentioned earlier, the reason that we proposed the methodology that we did was to address methodological concerns raised by the Commission regarding temperature normalization adjustments in earlier orders. Although the methodology that the Company proposed is statistically sound, a less complicated approach – particularly one that considers only a single CDD variable, a single HDD variable, and does not require step-wise regression – would certainly produce reasonable results, would be easier to validate and replicate, and could be used by other utilities in Kentucky without requiring the use of SAS or other special-purpose statistical software packages. Furthermore, because a banding approach is utilized, the statistical accuracy of the methodology becomes less important. If a less intricate -- but perhaps slightly less accurate -- methodology is utilized, then the two standard deviation banding proposed by the Company provides a measure of protection against any slight reduction in accuracy that may result from using the less complex methodology.

As an alternative to the methodology proposed by the Company, we would suggest performing a regression analysis for each month and for each class using HDD65, CDD65, and a weekend/holiday dichotomous variable (dummy variable). The inclusion of a weekend/holiday variable will significantly improve the fit of the models. If the R-square for the model falls below 0.60 then the model should be rejected and no temperature normalization adjustment would be made for the month or if the t-statistic for one of the two temperature variables falls below 1.8 then the temperature variable would be eliminated. The Company also recommends using the banding approach as described in my direct testimony. This is one of the methodologies that the Commission Staff asked LG&E to perform in Question No. 54 of its Second Data Request dated August 27, 2008.[4]

Q. Have you prepared an exhibit showing the calculation of the temperature adjustment using this alternative approach?

A. Yes. The temperature adjustment using this alternative methodology, which will be referred to as the "Methodology from Staff Data Request", is shown in Seelye Rebuttal Exhibit 1. The Methodology from Staff Data Request would result in a downward adjustment in test-year revenues of $15,777,062 and a downward adjustment in test-year expenses of $5,215,979.

[4] In Question 54 of its Second Data Request dated August 27, 2008, the Commission Staff asked the Company to "[p]rovide two revised runs of Seelye Exhibits 18 and 19, one which includes HDD65 and CDD65 as the only varaibles and a second which includes HDD60 and CDD70 as the only variables." The approach referenced herein is the first of these two methodologies.

Q. Have you also prepared an exhibit showing the calculation of the temperature adjustment using Mr. Watkins' approach, except modifying it to address some of the fundamental problems with his approach?

A. Yes. The temperature adjustment using Mr. Watkins' approach, except modifying it to include April, May, and October and to perform monthly banding is shown in Seelye Rebuttal Exhibit 2. The Modified Watkins Methodology would result in a downward adjustment in test-year revenues of $15,467,935 and a downward adjustment in test-year expenses of $5,208,413.

Q. Please summarize the effect on test-year operating results of the three methodologies?

A. As can be seen in the following table, the three methodologies produce similar results:

LOUISVILLE GAS AND ELECTRIC COMPANY COMPARISON OF ALTERNATIVE ELECTRIC TEMPERATURE NORMALIZATION METHODOLOGIES			
METHODOLOGY	**ADJUSTMENT TO REVENUES**	**ADJUSTMENT TO EXPENSES**	**ADJUSTMENT TO NET OPERATING INCOME BEFORE TAXES**
Company's Proposed Methodology	$ (14,374,348)	$ (4,751,178)	$ (9,623,170)
Methodology from Staff Data Request	$ (15,777,062)	$ (5,215,979)	$ (10,561,083)
Modified Watkins Methodology	$ (15,467,935)	$ (5,208,413)	$ (10,259,522)

I recommend that the Commission adopt either the Company's Proposed Methodology or the Methodology from Staff Data Request. The Company's Proposed Methodology is statistically rigorous and fully addresses the concerns raised by the Commission in prior orders. The Methodology from Staff Data Request has the advantage of requiring fewer steps, yet produces reasonable results. Furthermore, the Methodology from Staff Data Request would be easier to perform by other utilities and would not require special-purpose statistical software to implement step-wise regression procedure. In fact, the Methodology from Staff Data Request could be implemented without any difficulty in an Excel spreadsheet.

Even though the Modified Watkins Methodology produces similar results, I cannot recommend the approach. As I have explained, modeling sales on a month-by-month basis helps correct for the non-linear temperature response that is often evident in modeling across a full season. Modeling the data monthly is a less complicated alternative to piecewise regression, where regression is performed in a manner that accounts for different levels of responsiveness within various ranges of the independent variable.

Q. Have any other technical issues regarding the electric temperature normalization adjustment been raised by the intervenor witnesses?

A. Yes. Mr. Kollen questions whether the Company has properly supported the use of a 30-year period for determining normal temperature. Mr. Kollen also criticizes the methodology that the Company uses to calculate the expense component for the electric temperature normalization adjustment.

Q. Why did the Company propose a 30-year average for purposes of determining normal temperatures?

A. A 30-year average has always been used to calculate the gas temperature normalization adjustment. For the last twenty years or so the Commission has required that the 30-year average be determined using the most recent 30-year period, regardless of whether this corresponds to the 30-year average published by the National Oceanic and Atmospheric Administration (NOAA). It is important that the electric temperature normalization adjustment be consistent with the gas temperature normalization adjustment with respect the number of years used to calculate normal temperature. For example, it would be inconsistent and inappropriate to use 30 years to calculate the average HDDs for the gas temperature normalization adjustment but use 20 years to calculate the average HDDs and CDDs for the electric temperature normalization adjustment.

Q. Did Mr. Kollen object to using 30 years to calculate the average HDDs for the gas temperature normalization adjustment?

A. No.

Q. Is there any basis for using a shorter period because of warming patterns resulting from climate change?

A. I am not an atmospheric scientist and cannot offer an informed opinion about whether there is an upward or downward trend in temperatures. Mr. Watkins correctly pointed out that in some jurisdictions periods shorter than 30 years have been used to calculate the average while in other jurisdictions periods longer than 30 years have been used. It is instructive, however, that the mean temperatures reported by NOAA are still based on 30-year averages. The argument for using 30 years in calculating the average is that it includes more data points than, say, a 10- or a 20-year average. Using a larger number of sample points to calculate an average will generally lead to a better estimate of the mean value of a random variable. An average based on 30 years would also be less sensitive to the effects of outliers (i.e., a year with extreme weather) than a 20- or 10-year average. But if there is truly a verifiable time-ordered trend in the data, then using more years may not necessarily increase the accuracy of the mean-value estimate. Updating the average to reflect data for the most recent 30-year period, as required by the Commission for the gas temperature normalization adjustment, would certainly help capture any trend that might be present in the data.

Q. Would the Company object to using less than 30 years of data to calculate the average?

A. The Company continues to recommend calculating the average using 30 years for both the gas and the electric temperature normalization adjustments. However, the Company would not object to using 20 years to calculate the average as along as it is consistently applied to the gas temperature normalization adjustment, the gas Weather Normalization Adjustment (WNA) Rider, and the electric temperature normalization adjustment. We strongly recommend against using anything less than 20 years to calculate the average. The presence of outliers could potentially have too large of an impact on an average calculated using fewer than 20 years of data.

Q. Does Mr. Kollen raise a valid concern about the way that the expense adjustment is calculated?

A. No. Mr. Kollen recommends that the same methodology for calculating the expense side of the year-end customer annualization adjustment should be used to calculate the expense side of the electric temperature normalization adjustment. The *only* reason that he gives in support of this recommendation is that it would result in a larger reduction in expenses. Because a particular approach results in a larger reduction in test-year expenses is not a valid reason for adopting that methodology. The purpose of the year-end customer annualization adjustment is to reflect the difference between the revenues and expenses associated with serving the number of customers taking service at the end of the year and the actual revenues and expenses during the test year which presumably corresponded to serving the actual (or average) number of customers during the test year. The purpose of the electric temperature normalization adjustment is to reflect the difference in revenues and expenses associated with selling more (or less) kWh sales. The two adjustments are altogether different; therefore, there is no reason to assume, as Mr. Kollen does, that the expense side of the electric temperature normalization adjustment should be calculated using the same methodology as the year-end annualization adjustment. The two adjustments relate to different impacts on revenues and also relate to different impacts on expenses.

The only costs affected by the higher level of kWh sales resulting from hotter-than-normal weather are variable expenses. None of the Company's fixed costs are affected by changes in temperature-related kWh sales. This is not the case with serving new customers. Adding customers results in increased fixed expenses – both customer-related and demand-related expenses. For example, adding new customers results in additional meter reading expenses, billing expenses, transformer maintenance expenses, maintenance of services, customer information expenses, and other distribution expenses during the test year. In calculating the expense side of the year-end annualization adjustment, we followed the long-standing practice of applying an operating ratio to the revenue side of the adjustment. This approach gives consideration to the fact that expenses other than non-fuel variable expenses are affected by adding new customers. In calculating the expense side of the electric temperature adjustment, we multiplied the change in revenue by the non-fuel variable expenses identified from the FERC predominance methodology utilized in the Company's cost of service study. It should be noted that KIUC's cost of service witness, Stephen Baron, did not offer any criticisms of the FERC predominance methodology in his direct testimony.

Q. Did LG&E use a test year average Fuel Adjustment Clause ("FAC") factor to compute the expenses related to the weather normalization adjustment as Mr. Kollen claims in his testimony?

A. No. The actual base fuel factor was used in the calculation. The base fuel factor is the component included in base rates and does not vary from month to month. The

FAC factors are a separate rate mechanism from base rates and the revenue and expense impacts of the FAC are removed from base rate determination by the adjustment shown in Rives Exhibit 1, Reference Schedule 1.03 and the testimony of Robert M. Conroy. Therefore, the actual base fuel factor is the proper component to include in the weather normalization adjustment.

VI. ELECTRIC COST OF SERVICE STUDY

Q. What is the purpose of the cost of service study?

A. The purpose of the cost of service study is to determine the rate of return on rate base that LG&E is earning from each rate class, which provides an objective indication as to whether the Company's rates reflect the actual cost of providing service to each rate class. A cost of service study is useful in determining how the Company's proposed revenue increase should be allocated to the various rate classes and can be used as a guide in designing rates.

Q. Has the same cost of service methodology been used for a long time?

A. Yes. The methodology used in the cost of service study filed in this proceeding has been used by LG&E since 1980, when the Company was developing a time-differentiated cost of service study to comply with the Public Utility Regulatory Policies Act of 1978. Particularly, the same methodology for time-differentiating and allocating fixed production costs – namely the Modified Base-Intermediate-Peak (BIP) Methodology – has been used by LG&E since 1980, and the same methodology for classifying distribution costs – namely the zero-intercept methodology using weighted regression analysis – has also been used by LG&E since 1980. Importantly, these two methodologies have been utilized by the Company, and found to be reasonable by the Commission, for many years.

Q. Does AG Witness Watkins recommend against using the Modified BIP Methodology?

A. Yes. Mr. Watkins proposes the BIP Methodology instead of the Modified BIP Methodology.

Q. Was the "traditional" BIP methodology ever considered by LG&E?

A. Yes. It was rejected because it produced somewhat ridiculous results when applied to a generation mix that relied heavily on coal-fired generation. When the original BIP methodology was developed by EBASCO (an engineering consulting firm) in the late 1970s, the methodology was originally applied to utilities that had generation resource mixes that consisted of generating units that could be readily identified as "Base", "Intermediate", and "Peak" units. LG&E's resource mix consisted of a much larger percentage of base-load generation than the utilities originally used to test the BIP methodology. When LG&E hired EBASCO in 1980 to assist the Company in developing a time-differentiated cost of service study it quickly became apparent that the "traditional" BIP Methodology would not produce reasonable results. Specifically, when the traditional BIP Methodology was applied to LG&E's generation resources it produced peak period costs that were lower than off-peak costs, which was obviously a counter-intuitive result. LG&E worked closely with

EBASCO, the original developers of the BIP Methodology, to design a Modified BIP Methodology that would produce more reasonable results.

Q. Does an unmodified application of the BIP Methodology still produce counterintuitive results?

A. Yes. In his cost of service study, Mr. Watkins applied the traditional BIP Methodology to LG&E's fixed production costs. It still produces fixed production costs that are higher during the off-peak period than the winter on-peak period. As shown in Seelye Rebuttal Exhibit 3, Mr. Watkins' cost of service study produces off-peak fixed production costs of $0.017 per kWh and winter on-peak fixed production costs of $0.016. This demonstrates that there is a serious flaw in Mr. Watkins' cost of service study. Under no reasonable circumstance should fixed production costs be higher during the off-peak period than during an on-peak period. Because LG&E's generation *capacity* costs are unaffected by customers consuming more power during the off-peak period, a strong case can be made that production capacity costs are zero during the off-peak period.

Q. Is there any other indication that Mr. Watkins' misapplication of the "traditional" BIP methodology produces unrealistic results?

A. Yes. In Mr. Watkins' cost of service study, approximately 83 percent of LG&E's fixed production and transmission costs are allocated on the basis of an energy allocator. I can't recall ever seeing a cost of service study that allocates such a large percentage of production and transmission capacity costs on the basis of energy. LG&E has traditionally allocated approximately 30 percent of these capacity costs on the basis of an energy allocator. Allocating 83 percent of the Company's production and transmission capacity costs on the basis of energy is a direct consequence of his misapplication of the "traditional" BIP methodology. Mr. Watkins designated nearly all of LG&E's and KU's coal-fired steam units as "base" units without considering how the units are used to provide service to native load customers and, more significantly, without considering why the units were originally installed by the Companies. For more than thirty years, increases in peak demand have been driving the need for new generation capacity on the LG&E and KU systems. The Companies must have sufficient capacity to meet the maximum demand placed on the two systems; therefore, allocating 83 percent of production capacity costs on the basis of energy cannot be supported by cost of service principles.

Q. Does Mr. Watkins modify the way that the zero-intercept methodology is applied?

A. Yes. In LG&E's cost of service study, certain distribution costs are classified as customer-related or demand-related using a methodology that is referred to as a "zero-intercept" methodology. The idea behind the zero-intercept methodology is to determine using a regression analysis the portion of costs that are invariant with respect to the load-carrying capability of certain distribution facilities. The zero-intercept methodology is typically applied to overhead conductor, underground conductor, and transformers. In applying the zero-intercept methodology, LG&E has traditionally used a weighted regression analysis. Although Mr. Watkins accepts the zero-intercept methodology, he recommends that an unweighted least-squares regression analysis be used.

Q. Is it appropriate to use an unweighted regression analysis in performing the zero-intercept methodology?

A. No. Contrary to the assertions made by Mr. Watkins, weighted regression is not some type of bizarre mathematical trickery – or in his words "a clever mathematical exercise" that "violates theoretical statistical principles of linear regression and skews his results." On the contrary, weighted least squares is a standard regression methodology included in most commercially available statistical software packages, including SAS, SPSS, Minitab, S-Plus, and Matlab. Weighted least squares is also an accepted methodology covered in most standard reference books on multiple regression analysis.[5] If weighted least squares regression were merely a "clever mathematical exercise," it would not be included as a standard option in all of these statistical software packages and would not be described in so many textbooks on multiple regression analysis.

Weighted least squares is necessary in a zero intercept analysis because the summary data used in the analysis includes average cost information reflecting vastly different quantities of the various types of plant identified in the analysis. For

[5] For example, see Douglas C. Montgomery, Elizabeth A. Peck, and G. Geoffrey Vining, *Introduction to Linear Regression Analysis*, Fourth Edition (Wiley Series in Probability and Statistics: 2006), pp. 179-183; Samprit Chatterjee and Bertram Price, *Regression Analysis by Example*, First Edition (Wiley: 1978), pp. 101-115. The mathematical steps used by the Company to perform least squares regression in an Excel spreadsheet are described in the Chatterjee and Price textbook. Numerical techniques used to perform weighted least squares are discussed in Åke Björck, Numerical Methods for Least Squares Problems (Society for Industrial and Applied Mathematics, 1996). A copy of the sections dealing with weighted least squares is included in Seelye Rebuttal Exhibit 4.

example, in the cost data used to perform the zero intercept analysis for LG&E's transformers, there were 2,210 transformers with a size rating of 25 KVA but only five transformers with a size rating of 3000 KVA. On a very basic level, the 3000 KVA transformers – totaling only five transformers – should not be given the same weight in the analysis as the 25 KVA transformers when there are many times more of them included in the analysis. Using weighted least squares regression more accurately replicates the results that would be obtained if a regression were performed using cost data for each transformer rather than summary data (average) for each type of transformer. For instance, if cost data were available for each transformer (rather than each type of transformer), then the data for the 25 KVA transformers would have significantly more effect on the results of the regression analysis than the 3000 KVA transformers. In fact, there would be 2,205 more 25 KVA transformers in the regression analysis than 3000 KVA transformers, and the 25 KVA transformers would have a correspondingly larger impact on the results of the regression analysis. Obviously, if cost data were available for each and every transformer on the system, then the 3000 KVA transformers would have very little impact on the results of a regression analysis performed using cost data for each transformer. In fact, it is likely that the five 3000 KVA transformers could be removed from the analysis without indicating any noticeable effect on the regression coefficients.

The purpose of a zero-intercept analysis is to properly represent the actual composition of a utility's distribution facilities. If the analysis is weighted then it accomplishes this task. But if the analysis is not weighted, then the zero-intercept analysis will not accurately represent the distribution of the various types of overhead conductor, underground conductor, and line transformers actually installed by the utility, and will thus produce inaccurate results.

Q. Mr. Watkins claims that unweighted least squares regression is standard approach used to perform the zero-intercept analysis. Is he correct?

A. No. *The Electric Utility Cost Allocation Manual* published by the National Association of Regulatory Utility Commissioners ("NARUC"), January, 1992, clearly indicates that the zero-intercept analysis should be weighted. NARUC's *Electric Utility Cost Allocation Manual* provides the following instructions for overhead conductor, underground conductor and transformers:

> **Account 365 – Overhead Conductors and Devices**
>
> - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor *weighted* by feet or investment in each category, and developing a cost for the utility's minimum size conductor.
>
> **Account 366 and 367 – Underground Conductors and Devices**
>
> - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable *weighted* by feet of investment in each category.
>
> **Account 368 – Line Transformers**
>
> - Determine zero intercept of transformer cost using cost per transformer by type, *weighted* by number for each category.
>
> (NARUC's *Electric Utility Cost Allocation Manual*, January, 1992, pp. 93-94)

Mr. Watkins' claim that unweighted least squares regression represents the industry standard approach cannot be reconciled with these instructions from NARUC's *Electric Utility Cost Allocation Manual*, which clearly indicates that the analysis should be *weighted*.

Furthermore, I can say with absolute certainty that weighted regression has been utilized in applying the zero-intercept methodology by more than 150 utilities throughout the U.S. and Canada. Contrary to being simply a "clever mathematical exercise," as claimed by Mr. Watkins, weighted least squares regression is the standard approach used in the industry to perform zero-intercept analysis.

Q. Were cost of service studies utilizing weighted regression to perform the zero-intercept analysis found to be reasonable by the Commission in earlier Commission Orders?

A. Yes, on many occasions. For example, weighted least-squares regression was accepted by the Commission in its Order dated November 10, 2004, in Case No. 2004-00067 approving rates for Delta Natural Gas Company. The AG's own witness in that proceeding also utilized weighted least-squares regression to perform a zero-intercept analysis.

Q. In making his recommendation, has Mr. Watkins demonstrated that weighted least-squares regression produces incorrect results?

A. No. Calling weighted least-squares regression a "clever mathematical trick" does not demonstrate that it produces incorrect results. He claims that it "violates theoretical statistical principles of linear regression and skews his results" but he fails to indicate what "theoretical principles of linear regression" are violated and to demonstrate how the results are "skewed" by application of the methodology. Offering rhetoric without support is not sufficient grounds for arguing against weighted least-squares regression. It is incumbent on Mr. Watkins to *demonstrate* that weighted regression is mathematically flawed, statistically inaccurate, or otherwise produces incorrect results. He has not demonstrated that the methodology is flawed in any respect. Significantly, he has failed to recognize that a different type of regression methodology is required when analyzing *summary data* than when analyzing *individual unit cost data*.

Q. What is the difference between "summary data" and "individual unit cost data"?

A. In the context of a zero-intercept analysis, "individual unit cost data" refers to the cost of each *piece* (unit) of property recorded on the utility's books. In the case of line transformers, "individual unit cost data" would refer to the cost of each individual transformer purchased by the utility. Utilities generally do not retain information on the cost of each individual transformer that it has purchased, or at least not in any readily accessible database. Consequently, the data used to perform a zero-intercept analysis is almost always provided in *summary* form. With "summary data," the information retained for each type of transformer (or other types of property) includes the total cost of each transformer type and the total number of transformers (or units) by type. From this type of summary data, the *average unit cost* by transformer type can be calculated by dividing (i) the total cost for each type of transformer by (ii) the total number of transformers for that particular transformer type. This is the kind of *summary data* that is normally used to perform a zero intercept analysis.[6]

Q. Is it appropriate to use unweighted least-squares when analyzing *summary data*?

A. No. Although it would be appropriate to use unweighted regression if *individual unit cost data* were analyzed, using unweighted least squares regression to analyze summary data will almost certainly produce incorrect results. As unambiguously stated in NARUC's *Electric Utility Cost Allocation Manual,* the summary cost data for each type of property must be weighted by the number of units shown for each property type.

Q. Could you provide an example demonstrating that the failure to use weighted least squares will produce incorrect parameter estimates?

A. Yes. Perhaps the clearest way to demonstrate that unweighted regression yields incorrect results is to perform a least-squares regression analysis using *individual unit cost data* and compare the results of that analysis to the results of an unweighted regression analysis performed using *summary data* for the same dataset. Comparing the regression coefficients from the two procedures will demonstrate that performing unweighted regression using summary data will produce incorrect parameter estimates -- i.e., results that differ significantly from the "true" results determined from the underlying individual unit cost data. But we will be able to see that the parameter estimates determined by applying weighted least squares to the summary data will produce the exact same coefficients determined from the application of

[6] See NARUC's *Electric Utility Cost Allocation Manual*, January, 1992, pp. 93-94.

unweighted least-squares to the underlying data. These comparisons will thus invalidate the zero-intercept methodology recommended by Mr. Watkins but will confirm the methodology used by the Company.

Q. Please describe the underlying unit cost data used in your example.

A. In order to demonstrate the fundamental problem with using unweighted regression to analyze summary data, I will perform unweighted regression on a sample dataset containing individual unit cost data for six different transformer types. Specifically, the dataset includes twenty 25 KVA transformers, three 50 KVA transformers, twenty 100 KVA transformers, three 200 KVA transformers, and twenty 500 KVA transformers. The purpose of this sample is to illustrate the effect on a regression analysis of including transformer types for which there are relatively few units. In this case, there are only three 50 KVA transformers and three 200 KVA transformers. These two transformer types will not have a major impact on a regression analysis performed using the underlying data, but will have a major impact when Mr. Watkins' recommended methodology is applied to the summary data. I have limited the number of transformer types and the quantity of transformers to a minimum to make it easier to analyze the individual unit cost data. The unit cost data is shown in the following table:[7]

[7] It should be noted that while the data shown in the table represent purely hypothetical unit cost information virtually any realistic cost distribution could be utilized to demonstrate that Mr. Watkins' methodology will produce incorrect parameter estimates.

Transformer Type	25 KVA	50 KVA	100 KVA	200 KVA	500 KVA
Individual Unit Cost of Transformer	$ 400	$ 400	$ 1,800	$ 11,000	$ 7,800
	500	500	1,800	12,000	7,800
	600	600	1,900	13,000	7,900
	700		1,900		7,900
	800		2,000		8,000
	850		2,000		8,000
	900		2,000		8,000
	950		2,100		8,100
	950		2,100		8,100
	1,000		2,100		8,100
	1,000		2,100		8,100
	1,050		2,100		8,100
	1,050		2,100		8,100
	1,100		2,200		8,200
	1,150		2,200		8,200
	1,200		2,200		8,200
	1,300		2,300		8,300
	1,400		2,300		8,300
	1,500		2,400		8,400
	1,600		2,400		8,400
Average Unit Cost	$ 1,000	$ 500	$ 2,100	$ 12,000	$ 8,100

Q. **Please describe the results of performing a least squares regression analysis using this dataset.**

A. Because the dataset contains individual unit cost data, it is appropriate in this instance to use unweighted least-squares regression to calculate the intercept and slope coefficients. The least squares analysis is performed using the cost of each transformer as the dependent variable (y) and the transformer size (KVA) as the independent variable (x). Performing an unweighted regression analysis using this underlying data produces the following regression estimates:

$$y = a + bx$$
$$y = 929.97 + 15.10x$$

Stated another way, the intercept (a coefficient) of the model is $929.97 and the slope (b coefficient) is $15.10. The results of this regression analysis are shown in Seelye Rebuttal Exhibit 5.

Q. Do these parameter estimates represent accurate estimates of the liner model that best fit the data?

A. Yes. Because individual unit cost data is analyzed, unweighted least squares provides the parameter estimates for a linear model (i.e., a straight line) that most accurately fits the data.[8] Therefore, these parameter estimates can be used to evaluate the accuracy of model estimates determined from applying unweighted and weighted least-squares to summary data developed from the underlying dataset.

Q. How would unweighted least-squares regression (Mr. Watkin's approach) be performed using summary data?

A. The summary data for this dataset consists of the average cost of each type of transformer, as follows:

	Average Cost
25 KVA	$ 1,000
50 KVA	$ 500
100 KVA	$ 2,100
200 KVA	$12,000
500 KVA	$ 8,100

[8] This statement assumes that the standard "Euclidean" measure of distance between two points -- i.e., the square root of $((x-x_i)^2 + (y-y_i)^2)$ -- is the appropriate *norm* for purposes of performing regression analysis.

Using Mr. Watkins' approach, unweighted regression would be applied to these five data points without giving any consideration to the number of transformers installed for each transformer type. Applying unweighted least-squares regression to these five data points produces the following regression estimates:

$$y = a + bx$$
$$y = 1{,}750.42 + 17.08x$$

The intercept (a coefficient) of the model using Mr. Watkins' approach is $1,750.42 and the slope (b coefficient) is $17.08. These regression estimates are clearly not the same as those determined by performing least-squares regression using the individual unit cost data. The results of this regression analysis are shown in Seelye Rebuttal Exhibit 6.

Q. What conclusion can be drawn from this analysis?

A. It demonstrates that Mr. Watkins' methodology is fundamentally flawed. If his methodology were correct, then it would produce results that were somewhere close to the coefficients obtained from the underlying individual unit cost data. In this example, his methodology produces coefficients that are nowhere close to the original estimates.

Q. How would weighted least-squares regression (the standard approach used by the Company) be performed using summary data?

A. Using the methodology prescribed by NARUC's *Electric Utility Cost Allocation Manual* and utilized by the Company, the average cost of each type of transformer would be weighted by the number of units for each transformer type. Mathematically, this is done by weighting the squared differences by the number of units (n_i), and calculating the regression coefficients that minimize the sum of squared differences. Applying weighted least-squares regression to the five data points produces the following regression estimates:

$$y = a + bx$$
$$y = 929.97 + 15.10x$$

The intercept (a coefficient) of the model using the Company's approach is $929.97 and the slope (b coefficient) is $15.10.These regression estimates are exactly the same as those determined by performing least-squares regression using the individual unit cost data. The results of this regression analysis are shown in Seelye Rebuttal Exhibit 7.

Q. What conclusion can be drawn from this regression analysis?

A. It demonstrates that the methodology used by the Company is fundamentally sound and produces zero-intercept estimates that accurately represent the underlying data.

Q. Are there other problems with Mr. Watkins' cost of service study?

A. Yes. Although Mr. Watkins' cost of service study should be rejected for the reasons I have already discussed, his study also contains a large number of other errors and internal inconsistencies. Listed below are some of the more obvious problems:

(1) Mr. Watkins allocates fixed production and transmission costs using the "traditional" BIP Methodology but allocates margins on off-system sales using the Modified BIP Methodology which he has specifically recommended against. Off-system sales are asset-based power sales generated from the Company's generating resources but delivered to counterparties outside of the LG&E/KU control area. In a rate case, customers receive the full benefit of any margins from off-system sales. Particularly, margins from test-year off-system sales reduce the Company's revenue requirement in a rate case proceeding. In LG&E's cost of service study, margins on off-system sales are allocated on the same basis as production plant. The reason behind allocating off-system sales on the same basis as production plant is that if a customer class is allocated a certain portion of production capacity costs, then the customer class should receive a proportionate benefit from any margins received when the production facilities are used to generate power sold outside the system. By allocating production plant costs using the "traditional" BIP Methodology but allocating margins on on-system sales using the Modified BIP Methodology, there is a serious mismatch between the *costs* of production capacity allocated to each rate class and the *benefits* of the production capacity (off-system margins) allocated to each rate class. Throughout his cost of service study, Mr. Watkins' has made every effort to

allocate a larger amount of *costs* on the basis of energy but has been equally diligent about allocating *benefits* (revenues and other credits) on the basis of demand.

(2) Mr. Watkins allocates the pro-forma adjustment for storm damages (Rives Exhibit 1, Reference Schedule 1.18) using the distribution expense allocation factor from the Company's cost of service study even though he has modified the way the distribution expenses are allocated in his own cost of service study. In LG&E's cost of service study, the pro-forma adjustment for storm damages is allocated on the basis of distribution operation and maintenance expenses. In the Company's cost of service study, the allocation of distribution operation and maintenance expenses largely follows that allocation of distribution plant, which is classified using the Company's application of the zero-intercept methodology using weighted least-squares regression. In Mr. Watkins' cost of service study he has modified the way that distribution expenses are allocated but uses the Company's allocation of distribution expenses to allocate the pro-forma adjustment for storm damages. This is another example of a serious mismatch between the allocation of *costs* and the allocation of *credits* in Mr. Watkins' cost of service study. He allocates distribution expenses (a *cost*) using his zero-intercept methodology and allocates the pro-forma adjustment for storm damages (a *credit*) using the Company's zero-intercept methodology.

(3) Mr. Watkins uses a non-standard methodology for classifying production operation and maintenance expenses as fixed and variable in his cost of service study. There are two standard methodologies for classifying production

operation and maintenance expenses as fixed and variable – the FERC predominance methodology and the NARUC methodology – and Mr. Watkins uses neither approach. Under the "FERC predominance methodology", production operation and maintenance accounts that are predominately fixed, i.e. expenses that the FERC has determined to be predominately incurred independently of kilowatt hour levels of output are classified as demand-related. Production operation and maintenance accounts that are predominately variable, i.e., expenses that the FERC has determined to vary predominately with output (kWh) are considered to be energy related. The predominance methodology has been accepted in FERC proceedings for over 25 years and is a standard methodology for classifying production operation and maintenance expenses. For example, see *Public Service Company of New Mexico* (1980) 10 FERC ¶ 63,020, *Illinois Power Company* (1980), 11 FERC ¶ 63,040, *Delmarva Power & Light Company* (1981) 17 FERC ¶ 63,044, and *Ohio Edison Company* (1983) 24 FERC ¶ 63,068. The "NARUC methodology" is described on page 36-38 of NARUC's *Electric Utility Cost Allocation Manual*, January, 1992. Under the NARUC methodology, each production operation and maintenance expense account is either directly classified as entirely demand-related or entirely energy-related or is apportioned on the basis of labor and material expenses. In Mr. Watkins' cost of service study, most production operation and maintenance expense accounts are simply allocated on the basis of production plant.

Q. KIUC Witness Stephen J. Baron pointed out an error in the application of the BIP methodology. Do you agree with Mr. Baron?

A. Yes. We provided a corrected calculation of the BIP factors in a response to a data request. The BIP factors used by Mr. Baron are consistent with the corrected factors submitted by the Company.

Q. Do you agree with the results of his corrected cost of service study?

A. Yes.

Q. Please summarize the results of the cost of service study, as corrected to reflect the appropriate BIP factors:

A. The class rates of return based on the corrected cost of service study are summarized in the following table:

Customer Class	Proposed Rate of Return
Residential Rate RS	5.28%
General Service Rate GS	13.01%
Large Commercial – Rate LC	
- Primary	9.90%
- Secondary	11.07%
Industrial Power – Rate LP	
- Primary	11.65%
- Secondary	10.49%
Large Commercial Time of Day – Rate LC-TOD	
- Primary	7.33%
- Secondary	9.43%
Industrial Power Time of Day – Rate LP-TOD	
- Transmission	8.91%
- Primary	7.71%
- Secondary	11.26%
Small Commercial Time of Day – Rate STOD	
- Primary	4.58%
- Secondary	5.85%
Lighting	7.51%
Special Contracts	3.67%

Customer Class	Proposed Rate of Return
Total System	8.30%

It is the Company's recommendation that these class rates of return be used as a guide in allocating the revenue increase to the various classes of customers.

VII. ELECTRIC REVENUE ALLOCATION AND RATE DESIGN

Q. Do you agree with the allocation of the revenue increase proposed by Mr. Watkins?

A. No. Mr. Watkins' proposed allocation of the revenue increase to the rate classes is based on his flawed cost of service study. In allocating the increase to the classes of service, the Commission should be guided by LG&E's cost of service study, after correcting the study to reflect the appropriate BIP factors as described by Mr. Baron. Mr. Watkins' cost of service study should not be used as a guide for setting rates.

Q. Mr. Watkins recommends a lower residential customer charge than the one proposed by LG&E. Do you agree with his recommendation?

A. No. Even though Mr. Watkins claims that LG&E's monthly residential customer cost is only $2.98, he recommends leaving the monthly residential customer charge at the current level of $5.00. In calculating the $2.98 cost, which is shown in Exhibit ___6 of his testimony, Mr. Watkins ignores the results of his own cost of service study. In his own cost of service study, he classifies a portion of poles, overhead conductor, underground conductor, and transformers as customer related, but he ignores these same costs when he goes to calculate his proposed customer charge. Specifically, he only includes costs associated with services, meters, meter reading, and records and collections in the calculation of his proposed customer charge, ignoring costs associated with poles, overhead conductor, underground conductor, transformers and certain administrative and general expenses[9] that were classified as customer-related in his own cost of service study. The following table compares the costs identified as customer-related in Mr. Watkins' cost of service study with the costs that he considered customer-related for purposes of developing the customer charge:

COST ITEM	IDENTIFIED AS CUSTOMER-RELATED IN WATKINS' COST OF SERVICE STUDY	IDENTIFIED AS CUSTOMER-RELATED IN CALCULATING HIS CUSTOMER CHARGE
Poles	Yes	*No*
Overhead Conductor	Yes	*No*
Underground Conductor	Yes	*No*
Transformers	Yes	*No*
Services	Yes	Yes
Meters	Yes	Yes
Meter Reading	Yes	Yes
Records and Collection	Yes	Yes
Customer Accounts Supervision Expenses (Account 901)	Yes	*No*
Uncollectible Accounts (Account 904)	Yes	*No*
Miscellaneous Customer	Yes	*No*

[9] In Mr. Watkins' cost of service study he classifies administrative and general ("A&G") expenses using internally generated allocation factors that reference distribution expenses that were classified as customer related. Therefore, a portion of A&G expenses are classified as customer-related in Mr. Watkins' cost of service study.

COST ITEM	IDENTIFIED AS CUSTOMER-RELATED IN WATKINS' COST OF SERVICE STUDY	IDENTIFIED AS CUSTOMER-RELATED IN CALCULATING HIS CUSTOMER CHARGE
Accounts Expenses (Account 905)		
Customer Service Supervision (Account 907)	Yes	*No*
Customer Assistance Expense (Account 908)	Yes	*No*
Customer Information and Instruction (Account 909)	Yes	*No*
Miscellaneous Customer Service	Yes	*No*
A&G Expenses	Yes	*No*

In calculating his proposed customer charge, Mr. Watkins specifically excludes a large number of costs identified as customer-related in his own cost of service study, including costs classified as customer costs through the application of his zero-intercept analysis. However, in the one instance where he makes a subtraction in the calculation of the residential customer cost in his Exhibit ___6, he includes an item that was not even classified as a customer-related in his cost of service study. Specifically, he identified Account 587 - Customer Installation Expenses (which was a credit during the test year) as a customer cost even though this account was not classified as customer-related in his cost of service study.

By leaving costs out of his calculation of customer-related costs in his Exhibit ___6, Mr, Watkins calculates a residential customer charge of only $2.98. Seelye Rebuttal Exhibit 8 is a recalculation of Mr. Watkins' residential customer cost adding back in costs that were classified as customer-related in his own cost of service study. As can be seen from this exhibit, Mr. Watkins' own cost of service study indicates that the monthly customer cost for the residential class is $10.06 per customer per month.

Q. Has the Commission rejected this type of selective interpretation of the cost of service study in prior rate orders?

A. Yes. In its Order dated September 27, 2000, in Case No. 2000-080, an LG&E rate case, the Commission specifically rejected this same type of selective and attenuated approach for determining customer charges. Just as Mr. Watkins has done in the current proceeding, the AG's cost of service witness proposed a customer charge in Case No. 2000-080 that ignored costs identified as customer-related in the zero-intercept analysis. The Commission rejected the AG's calculation in that proceeding.

Q. Do you have any other comments regarding the customer charge recommended by Mr. Watkins?

A. Yes. LG&E is proposing a residential customer charge of $8.23 per month. In order to recommend a customer charge of only $5.00 per month, Mr. Watkins had to abuse his own cost of service study, which fully supports a $10.06 customer charge. As shown in Seelye Exhibit 2 of my direct testimony, LG&E's cost of service study would support a customer charge of $16.43. LG&E's proposed customer charge more accurately reflects the cost of providing service than Mr. Watkins' proposal. However, numerous other benefits of recovering fixed customer costs through the customer charge were identified in my direct testimony that were not refuted by Mr. Watkins or any other witness.

Unlike the Company's proposal, Mr. Watkins' proposed rate design would recover more of the Company's fixed customer-related costs through a "volumetric" charge (i.e., energy charge) and send incorrect price signals to customers. His proposal would increase the volatility in customer bills by collecting too much cost during peak months. Likewise, Mr. Watkins' proposal would increase the Company's revenue volatility.

Mr. Watkins' proposal would force customers such as low-income customers, whose energy use is greater than the average, to pay more than the cost of service, while allowing other customers to pay less than the cost of service. In his testimony in this proceeding, the witness for the Association of Community Ministries, Marlon Cummings, agrees with the Company's analysis which demonstrated that low-income customers use on average more electric energy than the average residential customer. Mr. Cummings states that, "Due to the fact that most low income residents rent or own housing with inadequate insulation and or heating apparatus the cost of low income household utilities is above the level of other utility users." (Case Nos. 2007-00564 and 2008-00252, Direct testimony of Marlon Watkins at p.6, lines 18-20.) This has been my experience in Kentucky and in every other jurisdiction where I have seen such comparisons made -- low-income customers use more electric energy than the average residential customer. Mr. Watkins proposal would further penalize these customers by charging them an average rate that moves further away from the cost of providing service.

Mr. Watkins proposal would provide a disincentive for LG&E to promote energy efficiency thus creating a poor regulatory environment for encouraging the Company to take additional measures for customers to reduce their energy usage. If customer-related fixed costs are inappropriately recovered through the energy charge rather than a fixed monthly customer charge, then the utility *ceteris paribus* will see a reduction in margins whenever customers reduce their consumption of electric energy as a result of improved energy efficiency. A number of regulators have recognized the need to make rate design changes that align the interests of utilities and customers so as not to penalize the utility when customers reduce their energy consumption as a result of improved efficiency. For example, in large part to insulate the utilities from the adverse financial consequences of improved energy efficiency, regulators in Missouri and Georgia have adopted a straight fixed-variable rate design for gas distribution utilities, which results in all fixed costs being recovered through a monthly access charge. Mr. Watkins regressive recommendation would take us back to the failed approaches of the 1970s, when the received view was to try to induce utility customers to reduce energy usage by increasing volumetric charges. The Company's approach is forward looking and more consistent with the progressive rate design philosophies that protect utilities against the lost revenues and margins that the utilities see when customers use energy more efficiently.

Q. But can't a properly designed demand-side management (DSM) recovery mechanism protect utilities against the adverse financial consequences of improved energy efficiency?

A. Not necessarily. Unless the mechanism includes some type of broad-based decoupling mechanism, which completely severs the relationship between energy sales and revenues, then a DSM mechanism will not shield the utility against customer-initiated improvements in energy efficiency. While the Company's DSM cost recovery mechanism includes a lost revenue component designed to provide limited recovery of lost net revenues from *company-initiated* programs, the mechanism does not include a decoupling mechanism and therefore will not recover lost revenues from *customer-initiated* energy efficiency efforts, such as replacing incandescent bulbs with more efficient compact fluorescent lamps (CFLs) or light emitting diodes (LEDs).

Q. Mr. Baron recommends increasing the credits received by industrial customers taking curtailable (CSR) service. Do you agree with his calculation?

A. I agree that the calculation performed by Mr. Baron to support his proposed CSR credits uses the same approach utilized by the Company in its last rate case. It is less clear though whether the credits for curtailable service should be increased at this time. The purpose of the calculation in the last rate case was to determine the CSR credits based on avoided generation capacity costs. Particularly, the CSR credits were based on the carrying costs of a new combustion turbine. As Mr. Baron correctly observes, the Company's estimate contained in the 2008 Integrated Resource Plan filed in April 2008 is that the installed cost of a new combustion turbine is $710 per kW and the annual fixed operation and maintenance cost is $12.20 per kW. Based on these estimates, the monthly fixed costs associated with a new combustion turbine is $8.51 per kW, which Mr. Baron recommends should be used to determine the CSR credit.

One of our concerns with using this estimate to determine the CSR credits is that the Company is currently purchasing capacity at a monthly cost significantly lower than $8.51 per kW. Specifically, as stated in Mr. Bellar's direct testimony in the KU proceeding (Case No. 2008-00251), in February 2008 KU entered into an agreement with Dynegy Power Marketing, Inc. to purchased capacity during the peak months (June through September) in 2008 and 2009 for 165 MW of capacity from a combustion turbine located in Oldham County, Kentucky. The monthly cost of the capacity from Dynegy was $346,500, which equates to a monthly cost of only $2.10 per kW. Therefore, from a near-term perspective, a strong argument could be made that the Company's avoided cost is no more than $2.10 per month especially considering that LG&E's need for additional capacity is primarily confined to the summer months.

Another concern that we have with using the Company's estimate of $710 per kW to determine the CSR credits is that this estimate represents a historically high cost for a combustion turbine. Just of few years ago, utilities could purchase combustion turbines from distressed independent power producers at a much lower cost. The point that needs to be considered is that the cost of combustion turbine capacity has been quite volatile over the past several years and that the Company's estimate represents the high end of the cost range seen during the past ten years. It should also be noted that the Energy Information Administration (the energy statistics department of the US government) lists the overnight cost of a conventional combustion turbine including contingencies at $500 per kW in its Electricity Market Module report released in June 2008.

Again, I agree that in developing his recommended CSR credits Mr. Baron used the same calculations submitted by the Company in its last rate case. While I understand his argument in support of higher CSR credits, Mr. Baron's recommended credits could overstate the value to the Company of curtailable service. But, of course, this is ultimately an issue for the Commission to decide.

VII. GAS COST OF SERVICE AND RATE DESIGN

Q. Mr. Watkins recommends a "Peak and Average" methodology for allocating distribution mains in the cost of service study. Do you agree with this approach?

A. No. In its gas cost of service study, LG&E classified distribution mains as either customer- or demand-related using the zero-intercept methodology. Costs classified as customer-related are then allocated to the customer classes based on the number of customers for each customer class, and costs classified as demand-related are then allocated on the basis of maximum class demands. This is the same methodology used to classify overhead and underground conductor in the electric cost of service study. It is important to note that Mr. Watkins also used the zero-intercept analysis to classify overhead and underground conductor in the cost of service study that he performed for LG&E's electric operations. For a gas utility, mains serve exactly the same function as overhead conductor and underground conductor for an electric utility – they both transport the product (electric energy or natural gas) to the customer. Mains and conductors are also similar in another key respect – the capacity to transport the product varies in direct proportion to the size (cross-sectional area) of the main or the conductor. It is for this reason that the zero-intercept methodology has been used for over 30 years to classify mains on the gas side of LG&E's business and to classify overhead and underground conductor on the electric side of the business. If it is appropriate to use a zero intercept analysis for classifying electric distribution lines, then it must also be appropriate to use a zero intercept analysis for classifying gas distribution mains. Therefore, Mr. Watkins' gas cost of service study is fundamentally at odds with his electric cost of service study. Because Mr. Watkins' gas cost of service study is so very inconsistent with his electric cost of service study, I suspect that Mr. Watkins is recommending the Peak and Average methodology merely because it would support assigning a larger portion of the revenue increase to LG&E's non-residential customers. This is not a valid reason for recommending a flawed cost of service methodology.

Q. Has the zero intercept methodology traditionally been used by LG&E to classify distribution mains?

A. Yes. The zero intercept methodology has been used by LG&E for at least 30 years.

Q. Has the Commission found the zero-intercept methodology to be reasonable in gas cost of service studies?

A. Yes. The Commission has found the zero-intercept methodology to be reasonable in numerous rate cases, including LG&E's last rate case for which a settlement agreement was not reached by the parties – Case No. 2000-080, Order dated September 27, 2000. NARUC's *Gas Distribution Rate Design Manual*, June 1989, identifies the zero intercept approach as a standard methodology for classifying gas distribution costs.[10]

Q. Besides being inconsistent with the methodology that Mr. Watkins uses to allocate conductor in his electric cost of service study and being inconsistent with a methodology that the Commission has found to be reasonable in numerous rate case orders, what objection do you have with using the Peak and Average Method for allocating gas distribution mains?

A. The Peak and Average Method allocates a portion of mains on the basis of demand and a portion on the basis of Mcf sales, and none on the basis of customers. While customers' maximum demand and the number of customers a utility serves has a direct impact on a utility's distribution costs, including the cost of mains, the annual quantity of gas sold by a utility has no effect whatsoever on cost of mains. From a distribution planning perspective, the installation of distribution mains is unaffected by amount of gas sold on an annual basis to its customers. A gas utility installs pipe

[10] Although NARUC's *Gas Distribution Rate Design Manual* also mentions the Peak and Average Methodology, the manual indicates on pp. 27-28 that it is a "compromise" methodology adopted because it "tempers the apportionment of costs between high and low load factor customers."

to reach its customers and to meet the peak load conditions of those customers. As long as the maximum demand requirements do not change, increases or decreases in annual throughput volumes do not have any impact on a utility's distribution costs, particularly the cost of mains. Because annual Mcf sales (or throughput volumes) do not have any effect on LG&E's investment in distribution mains, annual Mcf sales should not be used to allocate the cost of distribution mains. In its Order in Case No. 2000-080, the Commission specifically rejected a cost of service study that allocated a portion of mains on the basis of Mcf sales. Even though it has been recommended on numerous occasions, to the best of my knowledge, the Commission has never approved a cost of service study that allocated the cost of distribution mains on the basis of Mcf sales.

Q. Do you agree with the allocation of the revenue increase proposed by Mr. Watkins?

A. No. In allocating the increase to the classes of service, the Commission should be guided by LG&E's cost of service study. Mr. Watkins' proposed allocation of the revenue increase to the rate classes is based on his flawed cost of service study.

Q. Do you agree with the residential customer charge proposed by Mr. Watkins?

A. No. Mr. Watkins proposes to leave the residential customer charge at the current level of $8.50 per month. He supports this recommendation by performing a cost analysis that leaves out customer-related costs associated with distribution mains and also leaves out administrative and general expenses that were classified as customer-related costs in his own cost of service study.

Furthermore, Mr. Watkins failed to address the benefits described in my testimony for recovering fixed customer-related costs through the customer charge. As more fully described in the portion of my rebuttal testimony dealing with the electric customer charge, those benefits are:

(1) A cost-based customer charge sends a more accurate price signal to customers.

(2) With a cost-based customer charge, customers whose energy use is greater than the average, such as low-income customers, are not required to pay more than the actual cost of providing service.

(3) A cost-based customer charge does less to penalize the utility when customers use energy more efficiently.

(4) A cost-based customer charge helps stabilize customers' monthly bills.

(5) A cost-based customer charge helps stabilize the utility's monthly revenues.

It is my recommendation that the Commission approve the customer charges proposed by LG&E in this proceeding.

Q. Does this conclude your rebuttal testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principle with The Prime Group, that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

WILLIAM STEVEN SEELYE

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 17th day of December, 2008.

Tammy J. Ely (SEAL)
Notary Public

My Commission Expires:
November 9, 2010

Seelye Rebuttal Exhibit 1

LOUISVILLE GAS AND ELECTRIC COMPANY
Adjustment to Reflect Weather Normalized Electric Sales Margins
12 Months Ended April 30, 2008

HDD65 AND CDD65

	(1) kiloWatt-Hour Adjustment to Usage	(2) Energy Rate		(3) Revenue Adjustment		(4) Revenue Adjustment
				(2) * (1)		(3)
Residential Rate R	(201.410.000)	0 06404	$	(12.898.296 40)	$	(12.898.296)
General Service Rate GS	(24.032.000)		$	(1,771.154 64)	$	(1.771.155)
Single Phase	(9.277.000)		$	(684.380 57)		
Apr-2007	0	0 06849	$	-		
May-2007	-580.000	0.06849	$	(39.724 20)		
Jun-2007	-624.000	0 07621		(47.555 04)		
Jul-2007	0	0 07621		-		
Aug-2007	-3.375.000	0 07621		(257.208 75)		
Sep-2007	-2.348.000	0 07621		(178.941 08)		
Oct-2007	-2.350.000	0 06849		(160.951 50)		
Nov-2007	0	0 06849		-		
Dec-2007	0	0 06849		-		
Jan-2008	0	0.06849		-		
Feb-2008	0	0 06849		-		
Mar-2008	0	0.06849		-		
Apr-2008	0	0.06849		-		
Three Phase	(14 755 000)		$	(1.086.774.07)		
Apr-2007	0	0.06849	$	-		
May-2007	-894.000	0 06849	$	(61.230 06)		
Jun-2007	-838 000	0 07621		(63.863 98)		
Jul-2007	0	0.07621		-		
Aug-2007	-5.492.000	0.07621		(418.545 32)		
Sep-2007	-3 541.000	0 07621		(269.859 61)		
Oct-2007	-3.990.000	0.06849		(273.275 10)		
Nov-2007	0	0.06849		-		
Dec-2007	0	0.06849		-		
Jan-2008	0	0.06849		-		
Feb-2008	0	0.06849		-		
Mar-2008	0	0 06849		-		
Apr-2008	0	0 06849		-		
Large Commercial Rate LC	(31.272.000)		$	(853.985 76)	$	(853.986)
Secondary	(27.337.000)	0.02702	$	(738.645 74)		
Primary	(2.399.000)	0.02702	$	(64.820.98)		
Secondary Small Time of Day	(1,332.000)	0 03289	$	(43 809 48)		
Primary Small Time of Day	(204 000)	0 03289	$	(6.709 56)		
Large Commercial Rate LCTOD	(4.518.000)		$	(122.257 08)	$	(122.257)
Secondary	(3 186.000)	0 02706	$	(86.213 16)		
Primary	(1.332.000)	0 02706	$	(36.043 92)		
Industrial Power Rate LP	(4.535.000)		$	(106.889 95)	$	(106.890)
Secondary	(3,909.000)	0 02357	$	(92.135 13)		
Primary	(626.000)	0 02357	$	(14.754 82)		
Industrial Power Rate LPTOD	-		$	-	$	-
Secondary	-	0 02362	$	-		
Primary	-	0.02362	$	-		
Special Contracts	(1.035.000)		$	(24,477 75)	$	(24.478)
Fort Knox	(1.035.000)	0 02365	$	(24.477 75)		
DuPont	-	0.02379	$	-		
Louisville Water Company	-	0 02364	$	-		
Street Lighting Energy Rate SLE	-	-		-		
Traffic Lighting Rate TLE	-	-		-		
	Lights	*Lights*				
Public Street Lighting Rate PSL	-	-		-		
Outdoor Lighting Rate OL	-	-		-		
Total	(266.802.000)		$	(15.777,061 58)	$	(15.777.062)
Expenses (variable only)	(266.802.000)	0 01955	$	(5.215,979 10)	$	(5.215.979)
ADJUSTMENT TO NET OPERATING INCOME BEFORE TAXES					$	(10,561,083)

Seelye Rebuttal Exhibit 2

LOUISVILLE GAS AND ELECTRIC COMPANY
Adjustment to Reflect Weather Normalized Electric Sales Margins
12 Months Ended April 30, 2008

MODIFIED WATKINS METHODOLOGY (Seasonal Adjustments with Monthly Banding)
HDD65 AND CDD65

	(1) kiloWatt-Hour Adjustment to Usage	(2) Energy Rate		(3) Revenue Adjustment		(4) Revenue Adjustment
				(2) * (1)		(3)
Residential Rate R	(190.909.000)	0.06404	$	(12.225.812 36)	$	(12.225.812)
General Service Rate GS	(25.920.000)		$	(1,920.057 12)	$	(1 920.057)
Single Phase	(10.020,000)		$	(741.243 92)		
Apr-2007	0	0 06849	$	-		
May-2007	-586.000	0 06849	$	(40.135 14)		
Jun-2007	-609.000	0 07621		(46.411 89)		
Jul-2007	0	0 07621		-		
Aug-2007	-4.125.000	0 07621		(314.366 25)		
Sep-2007	-2.387.000	0.07621		(181.913 27)		
Oct-2007	-2.313.000	0 06849		(158.417 37)		
Nov-2007	0	0 06849		-		
Dec-2007	0	0 06849		-		
Jan-2008	0	0.06849		-		
Feb-2008	0	0 06849		-		
Mar-2008	0	0.06849		-		
Apr-2008	0	0 06849		-		
Three Phase	(15.900.000)		$	(1.178.813 20)		
Apr-2007	0	0.06849	$	-		
May-2007	-913.000	0.06849	$	(62.531 37)		
Jun-2007	-1.001.000	0 07621		(76.286 21)		
Jul-2007	0	0.07621		-		
Aug-2007	-6.781,000	0.07621		(516.780 01)		
Sep-2007	-3.853,000	0 07621		(293.637 13)		
Oct-2007	-3.352.000	0 06849		(229.578 48)		
Nov-2007	0	0 06849		-		
Dec-2007	0	0 06849		-		
Jan-2008	0	0.06849		-		
Feb-2008	0	0 06849		-		
Mar-2008	0	0 06849		-		
Apr-2008	0	0 06849		-		
Large Commercial Rate LC	(35.022.000)		$	(955.128 79)	$	(955.129)
Secondary	(31.187,000)	0 02702	$	(842.672 74)		
Primary	(2.330.000)	0 02702	$	(62.956 60)		
Secondary Small Time of Day	(1,301.000)	0 03289	$	(42.789 89)		
Primary Small Time of Day	(204.000)	0 03289	$	(6.709 56)		
Large Commercial Rate LCTOD	(6,731,000)		$	(182.140 86)	$	(182.141)
Secondary	(3.740.000)	0 02706	$	(101,204 40)		
Primary	(2.991.000)	0 02706	$	(80,936 46)		
Industrial Power Rate LP	(5.677.000)		$	(133.806 89)	$	(133.807)
Secondary	(4,864.000)	0 02357	$	(114,644 48)		
Primary	(813.000)	0 02357	$	(19.162 41)		
Industrial Power Rate LPTOD	-		$	-	$	-
Secondary	-	0 02362	$	-		
Primary	-	0 02362	$	-		
Special Contracts	(2.156.000)		$	(50.989 40)	$	(50.989)
Fort Knox	(2.156.000)	0 02365	$	(50.989.40)		
DuPont	-	0 02379	$	-		
Louisville Water Company	-	0 02364	$	-		
Street Lighting Energy Rate SLE	-	-		-		
Traffic Lighting Rate TLE	-	-		-		
	Lights	*Lights*				
Public Street Lighting Rate PSL	-	-		-		
Outdoor Lighting Rate OL	-	-		-		
Total	(266.415.000)		$	(15.467.935 42)	$	(15.467.935)
Expenses (variable only)	(266.415.000)	0 01955	$	(5.208.413 25)	$	(5.208.413)
ADJUSTMENT TO NET OPERATING INCOME BEFORE TAXES					$	(10,259,522)

Seelye Rebuttal Exhibit 2
Page 1 of 1

Seelye Rebuttal Exhibit 3

Production Plant Costs Assigned to Costing Period
in Watkins' Cost of Service Study
For Louisville Gas and Electric Company

	Total	Off-Peak Period	Winter On-Peak Period
Gross Production Plant	$2.204.761.687	$1.099.054.581	$535.397.071
Depreciation Reserve - Production	$1,056,980.153	$526.895.440	$256.673.581
Production Net Plant	$1.147.781.534	$572.159.141	$278.723.490
Production Expenses Allocated by Watkins on Production Plant			
502 Steam Exspenses	$27,325,773	$13.621,661	$6.635.701
505 Electric Expenses	$754.249	$375.986	$183.159
506 Misc Steam Power Expense	$16.989.296	$8,469,017	$4.125.625
507 Rents	$51,252	$25.549	$12.446
509 Allowances	$3.372	$1.681	$819
511 Maintenance of Structures	$2,279.365	$1.136.244	$553.513
536 Water For Power	$39.005	$19.444	$9.472
537 Hydraulic Expenses	$0	$0	$0
538 Electric Expenses	$161,489	$80.501	$39.215
539 Misc Hydraulic Power Expenses	$129,702	$64,655	$31.496
540 Rents	$238,696	$118,988	$57.964
542 Maintenance of Structures	$189,915	$94.671	$46.118
543 Maintenance of Reserves Dams. & Waterways	$87.399	$43.568	$21.224
546 Operation Supervision & Engineering	$28,825	$14,369	$7,000
548 Generation Expense	$925,321	$461.265	$224.702
549 Misc Other Power Generation	$37.851	$18,868	$9,192
550 Rents	$22,836	$11,384	$5.545
551 Maintenance Supervision & Engineering	$16,488	$8,219	$4,004
552 Maintenance of Structures	$91,930	$45,826	$22.324
553 Maintenance of Gen & Electric Plant	$1.860.881	$927.633	$451.890
554 Maintenance of Misc Other Power Generation	$110,415	$55,041	$26,813
555 Purchased Power - Demand	$10,759,242	$5,363,389	$2.612.739
556 System Control & Load Dispatch	$1,014,056	$505.498	$246.250
557 Other Expenses	-$570.439	-$284,359	-$138,524
Sub-Total	$62,546.919	$31,179.097	$15.188,688
Production Depreciation Expense	$65,807,165	$32.804.301	$15.980.395

Production Plant Costs Assigned to Costing Period
in Watkins' Cost of Service Study
For Louisville Gas and Electric Company

	Total	Off-Peak Period	Winter On-Peak Period
Revenue Requirement			
Interest	$28,120,648	$14.017.899	$6.828.725
Equity return	$60.235.575	$30,026.912	$14,627.409
Income Tax	$36,373,206	$18,131,728	$8.832.750
Revenue For Return	124.729,428	$62.176.538	$30,288,884
Production Expenses	$62.546,919	$31,179,097	$15.188.688
Depreciation Expense	$65.807.165	$32.804.301	$15,980.395
Total Plant Related Revenue Requirement	$253.083.513	$126.159.937	$61.457.967
kWh in Costing Period		7.600,383,678	3,777,854.650
Cost per Kwh		$0 017	$0 016

	PCT	Cost	WGHT Cost
Debt	47 52%	5.16%	2 45%
Common	52 48%	10.00%	5 25%
Total	100 00%		7 70%

Production Plant Costs Assigned to Costing Period
In Watkins' Cost of Service Study
For Louisville Gas and Electric Company

	Gross Plant	Costs Allocated to Off-Peak Period	Costs Allocated to Winter Peak Period	Costs Allocated to Summer Peak Period	Total
Base	$3.561.145	$2.178.688	$998.937	$383 520	$3,561 145
Intermediate	$86.352		$62 396	$23 956	$86 352
Peak	$723.066			$723.066	$723.066
Total	$4,370 563	$2,178 688	$1,061 333	$1,130 542	$4.370 563
Percentage of Total		49 85%	24.28%	25 87%	

	Hours	Percentage of Total
Off-Peak	5374	61 18%
Winter-Peak	2464	28 05%
Summer-Peak	946	10.77%
Total	8784	100 00%

	Hours	Percentage of Total
Winter-Peak	2464	72.26%
Summer-Peak	946	27.74%
Total	3410	100 00%

Seelye Rebuttal Exhibit 4

Introduction to Linear Regression Analysis

Fourth Edition

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that round-off error is potentially a problem and successive values of α may oscillate wildly unless enough decimal places are carried. Convergence problems may be encountered in cases where the error standard deviation σ is large or when the range of the regressor is very small compared to its mean. This situation implies that the data do not support the need for any transformation.

Example 5.4 The Windmill Data

We will illustrate this procedure using the windmill data in Example 5.2. The scatter diagram in Figure 5.5 suggests that the relationship between DC output (y) and wind speed (x) is not a straight line and that some transformation on x may be appropriate.

We begin with the initial guess $\alpha_0 = 1$ and fit a straight-line model, giving $\hat{y} = 0.1309 + 0.2411x$. Then defining $w = x \ln x$, we fit Eq. (5.8) and obtain

$$\hat{y} = \hat{\beta}_0^* + \hat{\beta}_1^* x + \hat{\gamma} w = -2.4168 + 1.5344x - 0.4626w$$

From Eq. (5.10) we calculate

$$\alpha_1 = \frac{\hat{\gamma}}{\hat{\beta}_1} + 1 = \frac{-0.4626}{0.2411} + 1 = -0.92$$

as the improved estimate of α. Note that this estimate of α is very close to -1, so that the reciprocal transformation on x actually used in Example 5.2 is supported by the Box–Tidwell procedure.

To perform a second iteration, we would define a new regressor variable $x' = x^{-0.92}$ and fit the model

$$\hat{y} = \hat{\beta}_0 + \hat{\beta}_1 x' = 3.1039 - 6.6784x'$$

Then a second regressor $w' = x' \ln x'$ is formed and we fit

$$\hat{y} = \hat{\beta}_0^* + \hat{\beta}_1^* x' + \hat{\gamma} w' = 3.2409 - 6.445x' + 0.5994w'$$

The second-step estimate of α is thus

$$\alpha_2 = \frac{\hat{\gamma}}{\hat{\beta}_1} + \alpha_1 = \frac{0.5994}{-6.6784} + (-0.92) = -1.01$$

which again supports the use of the reciprocal transformation on x.

5.5 GENERALIZED AND WEIGHTED LEAST SQUARES

Linear regression models with nonconstant error variance can also be fitted by the method of **weighted least squares**. In this method of estimation the deviation between the observed and expected values of y_i is multiplied by a **weight** w_i chosen inversely proportional to the variance of y_i. For the case of simple linear regression, the weighted least-squares function is

$$S(\beta_0, \beta_1) = \sum_{i=1}^{n} w_i(y_i - \beta_0 - \beta_1 x_i)^2 \tag{5.11}$$

The resulting least-squares normal equations are

$$\begin{aligned} \hat{\beta}_0 \sum_{i=1}^{n} w_i + \hat{\beta}_1 \sum_{i=1}^{n} w_i x_i &= \sum_{i=1}^{n} w_i y_i \\ \beta_0 \sum_{i=1}^{n} w_i x_i + \hat{\beta}_1 \sum_{i=1}^{n} w_i x_i^2 &= \sum_{i=1}^{n} w_i x_i y_i \end{aligned} \tag{5.12}$$

Solving Eq. (5.12) will produce weighted least-squares estimates of β_0 and β_1.

In this section we give a development of weighted least squares for the multiple regression model. We begin by considering a slightly more general situation concerning the structure of the model errors.

5.5.1 Generalized Least Squares

The assumptions usually made concerning the linear regression model $\mathbf{y} = \mathbf{X}\boldsymbol{\beta} + \boldsymbol{\varepsilon}$ are that $E(\boldsymbol{\varepsilon}) = \mathbf{0}$ and that $\text{Var}(\boldsymbol{\varepsilon}) = \sigma^2\mathbf{I}$. As we have observed, sometimes these assumptions are unreasonable, so that we will now consider what modifications to these in the ordinary least-squares procedure are necessary when $\text{Var}(\boldsymbol{\varepsilon}) = \sigma^2\mathbf{V}$, where $\mathbf{V}$ is a known $n \times n$ matrix. This situation has an easy interpretation; if $\mathbf{V}$ is diagonal but with unequal diagonal elements, then the observations $\mathbf{y}$ are **uncorrelated** but have **unequal variances**, while if some of the off-diagonal elements of $\mathbf{V}$ are nonzero, then the observations are **correlated**.

When the model is

$$\begin{gathered} \mathbf{y} = \mathbf{X}\boldsymbol{\beta} + \boldsymbol{\varepsilon} \\ E(\boldsymbol{\varepsilon}) = \mathbf{0}, \text{Var}(\boldsymbol{\varepsilon}) = \sigma^2\mathbf{V} \end{gathered} \tag{5.13}$$

the ordinary least-squares estimator $\hat{\boldsymbol{\beta}} = (\mathbf{X}'\mathbf{X})^{-1}\mathbf{X}'\mathbf{y}$ is no longer appropriate. We will approach this problem by transforming the model to a new set of observations that satisfy the standard least-squares assumptions. Then we will use ordinary least squares on the transformed data. Since $\sigma^2\mathbf{V}$ is the covariance matrix of the errors, $\mathbf{V}$ must be nonsingular and positive definite, so there exists an $n \times n$ nonsingular symmetric matrix $\mathbf{K}$, where $\mathbf{K}'\mathbf{K} = \mathbf{K}\mathbf{K} = \mathbf{V}$. The matrix $\mathbf{K}$ is often called the **square root** of $\mathbf{V}$. Typically, σ^2 is unknown, in which case $\mathbf{V}$ represents the assumed structure of the variances and covariances among the random errors apart from a constant.

Define the new variables

$$\mathbf{z} = \mathbf{K}^{-1}\mathbf{y}, \quad \mathbf{B} = \mathbf{K}^{-1}\mathbf{X}, \quad \mathbf{g} = \mathbf{K}^{-1}\boldsymbol{\varepsilon} \tag{5.14}$$

so that the regression model $\mathbf{y} = \mathbf{X}\boldsymbol{\beta} + \boldsymbol{\varepsilon}$ becomes $\mathbf{K}^{-1}\mathbf{y} = \mathbf{K}^{-1}\mathbf{X}\boldsymbol{\beta} + \mathbf{K}^{-1}\boldsymbol{\varepsilon}$, or

$$\mathbf{z} = \mathbf{B}\boldsymbol{\beta} + \mathbf{g} \tag{5.15}$$

The errors in this transformed model have zero expectation, that is, $E(\mathbf{g}) = \mathbf{K}^{-1}E(\boldsymbol{\varepsilon}) = \mathbf{0}$. Furthermore, the covariance matrix of $\mathbf{g}$ is

$$\begin{aligned}
\mathrm{Var}(\mathbf{g}) &= \{[\mathbf{g} - E(\mathbf{g})][\mathbf{g} - E(\mathbf{g})]'\} \\
&= E(\mathbf{g}\mathbf{g}') \\
&= E(\mathbf{K}^{-1}\boldsymbol{\varepsilon}\boldsymbol{\varepsilon}'\mathbf{K}^{-1}) \\
&= \mathbf{K}^{-1}E(\boldsymbol{\varepsilon}\boldsymbol{\varepsilon}')\mathbf{K}^{-1} \\
&= \sigma^2\mathbf{K}^{-1}\mathbf{V}\mathbf{K}^{-1} \\
&= \sigma^2\mathbf{K}^{-1}\mathbf{K}\mathbf{K}\mathbf{K}^{-1} \\
&= \sigma^2\mathbf{I}
\end{aligned} \tag{5.16}$$

Thus, the elements of $\mathbf{g}$ have mean zero and constant variance and are uncorrelated. Since the errors $\mathbf{g}$ in the model (5.15) satisfy the usual assumptions, we may apply ordinary least squares. The least-squares function is

$$S(\boldsymbol{\beta}) = \mathbf{g}'\mathbf{g} = \boldsymbol{\varepsilon}'\mathbf{V}^{-1}\boldsymbol{\varepsilon} = (\mathbf{y} - \mathbf{X}\boldsymbol{\beta})'\mathbf{V}^{-1}(\mathbf{y} - \mathbf{X}\boldsymbol{\beta}) \tag{5.17}$$

The least-squares normal equations are

$$(\mathbf{X}'\mathbf{V}^{-1}\mathbf{X})\hat{\boldsymbol{\beta}} = \mathbf{X}'\mathbf{V}^{-1}\mathbf{y} \tag{5.18}$$

and the solution to these equations is

$$\hat{\boldsymbol{\beta}} = (\mathbf{X}'\mathbf{V}^{-1}\mathbf{X})^{-1}\mathbf{X}'\mathbf{V}^{-1}\mathbf{y} \tag{5.19}$$

Here $\hat{\boldsymbol{\beta}}$ is called the **generalized least-squares estimator** of $\boldsymbol{\beta}$.

It is not difficult to show that $\hat{\boldsymbol{\beta}}$ is an unbiased estimator of $\boldsymbol{\beta}$. The covariance matrix of $\hat{\boldsymbol{\beta}}$ is

$$\mathrm{Var}(\hat{\boldsymbol{\beta}}) = \sigma^2(\mathbf{B}'\mathbf{B})^{-1} = \sigma^2(\mathbf{X}'\mathbf{V}^{-1}\mathbf{X})^{-1} \tag{5.20}$$

Appendix C.11 shows that $\hat{\boldsymbol{\beta}}$ is the best linear unbiased estimator of $\boldsymbol{\beta}$. The analysis of variance in terms of generalized least squares is summarized in Table 5.8.

TABLE 5.8 Analysis of Variance for Generalized Least Squares

Source	Sum of Squares	Degrees of Freedom	Mean Square	F_0
Regression	$SS_R = \hat{\boldsymbol{\beta}}'\mathbf{B}'\mathbf{z}$ $= \mathbf{y}'\mathbf{V}^{-1}\mathbf{X}(\mathbf{X}'\mathbf{V}^{-1}\mathbf{X})^{-1}\mathbf{X}'\mathbf{V}^{-1}\mathbf{y}$	p	SS_R/p	MS_R/MS_{Res}
Error	$SS_{Res} = \mathbf{z}'\mathbf{z} - \hat{\boldsymbol{\beta}}'\mathbf{B}'\mathbf{z}$ $= \mathbf{y}'\mathbf{V}^{-1}\mathbf{y}$ $- \mathbf{y}'\mathbf{V}^{-1}\mathbf{X}(\mathbf{X}'\mathbf{V}^{-1}\mathbf{X})^{-1}\mathbf{X}'\mathbf{V}^{-1}\mathbf{y}$	$n - p$	$SS_{Res}/(n-p)$	
Total	$\mathbf{z}'\mathbf{z} = \mathbf{y}'\mathbf{V}^{-1}\mathbf{y}$	n		

5.5.2 Weighted Least Squares

When the errors $\boldsymbol{\varepsilon}$ are uncorrelated but have unequal variances so that the covariance matrix of $\boldsymbol{\varepsilon}$ is

$$\sigma^2\mathbf{V} = \sigma^2\begin{bmatrix} \frac{1}{w_1} & & & 0 \\ & \frac{1}{w_2} & & \\ & & \ddots & \\ 0 & & & \frac{1}{w_n} \end{bmatrix}$$

say, the estimation procedure is usually called **weighted least squares.** Let $\mathbf{W} = \mathbf{V}^{-1}$. Since $\mathbf{V}$ is a diagonal matrix, $\mathbf{W}$ is also diagonal with diagonal elements or **weights** $w_1, w_2, \ldots, w_n$. From Eq. (5.18), the weighted least-squares normal equations are

$$(\mathbf{X}'\mathbf{W}\mathbf{X})\hat{\boldsymbol{\beta}} = \mathbf{X}'\mathbf{W}\mathbf{y}$$

This is the multiple regression analogue of the weighted least-squares normal equations for simple linear regression given in Eq. (5.12). Therefore,

$$\hat{\boldsymbol{\beta}} = (\mathbf{X}'\mathbf{W}\mathbf{X})^{-1}\mathbf{X}'\mathbf{W}\mathbf{y}$$

is the **weighted least-squares estimator.** Note that observations with large variances will have smaller weights than observations with small variances.

Weighted least-squares estimates may be obtained easily from an ordinary least-squares computer program. If we multiply each of the observed values for the ith observation (including the 1 for the intercept) by the square root of the weight for that observation, then we obtain a transformed set of data:

$$\mathbf{B} = \begin{bmatrix} 1\sqrt{w_1} & x_{11}\sqrt{w_1} & \cdots & x_{1k}\sqrt{w_1} \\ 1\sqrt{w_2} & x_{21}\sqrt{w_2} & \cdots & x_{2k}\sqrt{w_2} \\ \vdots & \vdots & & \vdots \\ 1\sqrt{w_n} & x_{n1}\sqrt{w_n} & \cdots & x_{nk}\sqrt{w_n} \end{bmatrix}, \quad \mathbf{z} = \begin{bmatrix} y_1\sqrt{w_1} \\ y_2\sqrt{w_2} \\ \vdots \\ y_n\sqrt{w_n} \end{bmatrix}$$

Now if we apply ordinary least squares to these transformed data, we obtain

$$\hat{\boldsymbol{\beta}} = (\mathbf{B}'\mathbf{B})^{-1}\mathbf{B}'\mathbf{z} = (\mathbf{X}'\mathbf{W}\mathbf{X})^{-1}\mathbf{X}'\mathbf{W}\mathbf{y}$$

the weighted least-squares estimate of $\boldsymbol{\beta}$.

SAS will do weighted least squares. The user must specify a "weight" variable, for example, w. To perform weighted least squares, the user adds the following statement after the model statement:

```
weight w;
```

5.5.3 Some Practical Issues

To use weighted least squares, the weights w_i must be known. Sometimes prior knowledge or experience or information from a theoretical model can be used to determine the weights (for an example of this approach, see Weisberg [1985]). Alternatively, residual analysis may indicate that the variance of the errors may be a function of one of the regressors, say $\text{Var}(\varepsilon_i) = \sigma^2 x_{ij}$, so that $w_i = 1/x_{ij}$. In some cases y_i is actually an average of n_i observations at x_i and if all original observations have constant variance σ^2, then the variance of y_i is $\text{Var}(y_i) = \text{Var}(\varepsilon_i) = \sigma^2/n_i$, and we would choose the weights as $w_i = n_i$. Sometimes the primary source of error is measurement error and different observations are measured by different instruments of unequal but known (or well-estimated) accuracy. Then the weights could be chosen inversely proportional to the variances of measurement error. In many practical cases we may have to guess at the weights, perform the analysis, and then reestimate the weights based on the results. Several iterations may be necessary.

Since generalized or weighted least squares requires making additional assumptions regarding the errors, it is of interest to ask what happens when we fail to do this and use ordinary least squares in a situation where $\text{Var}(\boldsymbol{\varepsilon}) = \sigma^2\mathbf{V}$ with $\mathbf{V} \neq \mathbf{I}$. If ordinary least squares is used in this case, the resulting estimator $\hat{\boldsymbol{\beta}} = (\mathbf{X}'\mathbf{X})^{-1}\mathbf{X}'\mathbf{y}$ is still unbiased. However, the ordinary least-squares estimator is no longer a minimum-variance estimator. That is, the covariance matrix of the ordinary least-squares estimator is

$$\text{Var}(\hat{\boldsymbol{\beta}}) = \sigma^2(\mathbf{X}'\mathbf{X})^{-1}\mathbf{X}'\mathbf{V}\mathbf{X}(\mathbf{X}'\mathbf{X})^{-1} \tag{5.21}$$

and the covariance matrix of the generalized least-squares estimator (5.20) gives smaller variances for the regression coefficients. Thus, generalized or weighted least squares is preferable to ordinary least squares whenever $\mathbf{V} \neq \mathbf{I}$.

Regression Analysis by Example

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CHAPTER 5

Weighted Least Squares

5.1. INTRODUCTION

In the preceding chapters, 1 through 4, it has been assumed that the underlying correct regression model is of the form

$$Y_i = \beta_0 + \beta_1 X_{1i} + \cdots + \beta_p X_{pi} + u_i, \tag{5.1}$$

where u_i's are random disturbances that are independent and identically distributed (i.i.d.). Various residual plots have been used to check these assumptions. If the residuals are not consistent with the assumptions, it is suggested that either the equation form is inadequate, some additional variables are required, or some of the data observations are outliers.

There has been one exception to this line of analysis. In the example based on the Supervisor data of Chapter 2, it was argued that the underlying model did not have residuals that were i.i.d. In particular, the residuals did not have constant variance. This situation (nonconstant residual variance) is often referred to as heteroscedasticity. The presence of unequal variances violates one of the basic ordinary least squares (OLS) assumptions. If OLS is applied, ignoring heteroscedasticity, the estimated coefficients are still unbiased, but are no longer best in the sense of precision (variance). For the Supervisor data, a transformation was imposed to correct the situation so that better estimates of the original model parameters could be obtained (better than OLS).

In this chapter and the one that follows, we investigate some regression situations where the underlying process implies that the regression residuals are not i.i.d. In the present chapter, heteroscedasticity is discussed. The problem is resolved by applying variations of weighted least squares (WLS). In the next chapter regression models with residuals that are not independent are treated. The approach in both situations is to use a combination of prior knowledge, intuition, and evidence found in the OLS residuals to detect the problem. The solution is usually prescribed as a two-stage procedure. In stage 1, the OLS residuals are used to estimate the parameters of the residual structure. In the second stage, these estimates are used to define a transformation or procedure that corrects for the lack of i.i.d. residuals and to produce estimates of the regression coefficients that usually have more precision than the OLS estimates.

5.2. HETEROSCEDASTIC MODELS

Three different heteroscedastic situations will be distinguished. The first two situations are fairly simple. In these two cases, once the necessity for WLS has been recognized, estimation can be accomplished in one step. The third situation is more complex and requires a two-stage estimation procedure. An example of the first heteroscedastic situation is found in Chapter 2 and will be reviewed here. The second situation is formulated, but no data is analyzed. The third heteroscedastic situation is demonstrated with two examples.

5.3. SUPERVISOR DATA

The first heteroscedastic situation has been treated in Chapter 2. There, data on X, the number of workers in an industrial establishment, and Y, the number of supervisors in the establishment were presented for 27 establishments. The regression model was

$$Y_i = \beta_0 + \beta_1 X_i + u_i. \tag{5.2}$$

It was argued that the variance of u_i depends on the size of the establishment as measured by X; that is, $\sigma_{u_i}^2 = k^2 X_i^2$ where k is a positive constant. (See Chapter 2 for details.) Empirical evidence for this type of heteroscedasticity is obtained by plotting the OLS residuals against X. A plot with the characteristics of Figure 5.1 typifies the situation. If corrective action is not taken and OLS is applied to the raw data, the resulting estimated coefficients will lack precision in a theoretical sense. In addition, for the type of heteroscedasticity present in this data, the estimated standard errors of the regression coefficients are often understated giving a false sense of precision. The problem is resolved by using a version of weighted least squares as described in Chapter 2.

This approach to heteroscedasticity may also be considered in multiple regression models. In Equation (5.1) the variance of the residuals may be affected by only one of the explanatory variables. (The case where the variance is a function of more than one explanatory variable is discussed

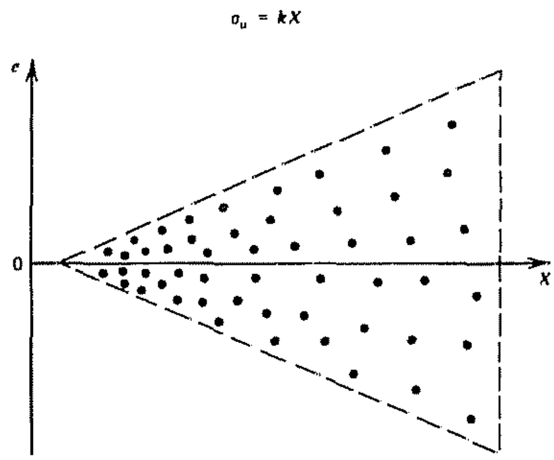

Fig. 5.1 Heteroscedastic residuals.

later.) Empirical evidence is available from the plot of OLS residuals versus the suspected variable and correction is accomplished by extending the method applied in Chapter 2. The resulting estimates are obtained by a transformation of the data. For example, if the original model is given as Equation (5.1) and it is found that $\sigma_{u_i} = kX_{4i}$, then the estimates are produced by regressing Y_i/X_{4i} against $1/X_{4i}, X_{1i}/X_{4i}, \ldots, X_{3i}/X_{4i}, X_{5i}/X_{4i}, \ldots, X_{pi}/X_{4i}$. The resulting coefficient of $1/X_{4i}$ is b_0, an estimate of β_0, the coefficient of X_{1i}/X_{4i} is an estimate of β_1, and so on, and the intercept from the regression is an estimate of β_4. Refer to Chapter 2 for a detailed discussion of this method as applied in simple regression.

5.4. COLLEGE EXPENSE DATA

A second heteroscedastic situation arises frequently with large-scale survey data where measurements on individual sampling units are averaged over a well-defined cluster of units in order to obtain increased stability. Only the average and number of sampling units are reported as data. For example, consider a survey of undergraduate college students (or their parents) that is intended to assess total annual college-related expenses. Assume that the survey is also intended to collect information that will make it possible to relate expenses to characteristics of the institution attended. Regression analysis may be used with a model such as

$$Y_i = \beta_0 + \beta_1 X_{1i} + \beta_2 X_{2i} + \cdots + \beta_6 X_{6i} + u_i. \qquad (5.3)$$

The variables are defined in Table 5.1. The data may be collected by selecting a set of schools at random and then interviewing a prescribed number of randomly selected students at each school. The explanatory variables are characteristics of the school with the exception of X_6, which can be taken as an average over the student population. (The logic behind choosing these explanatory variables is left to the imagination of the reader.) Rather than using total expense Y for each student interviewed, the average expense for these students at each institution serves as the dependent variable. The precision of average expenditure is directly proportional to the square root of the sample size on which the average is based. That is, the variance of $\bar{Y}$ is σ^2/n and its standard deviation is $\sigma/\sqrt{n}$. If there are k institutions in the sample and $n_1, n_2, \ldots, n_k$ represent the number of students interviewed at each institution, the standard deviation of u_i in the model (Equation (5.1)) is $\sigma_{u_i} = \sigma/\sqrt{n_i}$ where σ is the standard deviation for annual expense for the population of individual students. Estimation of the regression coefficients is carried out using WLS with weights $w_i = 1/\sigma_{u_i}^2$ as in Chapter 2. Since $\sigma_{u_i}^2 = \sigma^2/n_i$, the regression coefficients are obtained by minimizing the weighted sum of squared residuals,

$$S = \sum_{i=1}^{k} n_i \left(Y_i - \beta_0 - \sum_{j=1}^{6} \beta_j X_{ji} \right)^2. \tag{5.4}$$

Note that the procedure implicitly recognizes that observations from institutions where a large number of students were interviewed are more reliable and should have more weight in determining the regression coefficients than observations from institutions where only a few students were interviewed. The differential precision associated with different observation may be taken as a justification for the weighting scheme.

The estimated coefficients and summary statistics may be computed

Table 5.1. Variables in cost of education survey

Name	Description
Y	Total annual expense (above tuition)
X_1	Size of city or town where school is located
X_2	Distance to nearest urban center
X_3	Type of school—public, private
X_4	Size of student body
X_5	Proportion of entering freshman that graduate
X_6	Distance from home

using a special WLS computer program or by transforming the data and using OLS as in the example in Chapter 2. If both sides of Equation (5.1) are multiplied by $n_i^{1/2}$, the new model will have residuals, $\epsilon_i = u_i \cdot n_i^{1/2}$ and $\sigma_{\epsilon_i} = \sigma$, a constant. That is, the regression model stated in the new variables is

$$Y_i n_i^{1/2} = \beta_0 n_i^{1/2} + \beta_1 X_{1i} n_i^{1/2} + \cdots + \beta_6 X_{6i} n_i^{1/2} + \epsilon_i. \tag{5.5}$$

The residuals in Equation (5.5) satisfy the necessary assumption of constant variance. Regression of $Y_i \cdot n_i^{1/2}$ against the seven new variables consisting of $n_i^{1/2}$, and the six transformed explanatory variables, $X_{ji} n_i^{1/2}$ using OLS will produce the desired estimates of the regression coefficients and their standard errors. Note that the regression with the transformed variables must be carried out with the constant term constrained to be zero. That is, β_0, the intercept of the original model is now the coefficient of $n_i^{1/2}$. Equation (5.5) has no intercept. More details on this point are given with the numerical example in section 5.6.

5.5. TWO-STAGE ESTIMATION

In the two preceding problems heteroscedasticity was expected at the outset. In the first problem the nature of the process under investigation suggests residual variances that increase with the size of the explanatory variable. In the second case, the method of data collection indicates heteroscedasticity. In both cases, homogeneity of variance is accomplished by a transformation. The transformation is constructed directly from information in the raw data. In the problem described in this section, there is also some prior indication that the variances are not equal. But here the exact structure of heteroscedasticity is determined empirically. As a result, estimation of the regression parameters requires two stages.

It is not a simple matter to detect heteroscedasticity in a general multiple regression situation. If present it is often discovered as a result of some good intuition on the part of the analyst on how observations may be grouped or clustered. For multiple regression models, the plot of residuals against $\hat{Y}_i$, the fitted values of the response variable, can serve as a first step. If the magnitude of the residuals appears to vary systematically with $\hat{Y}_i$, *heteroscedasticity is suggested.* The plot does not necessarily clearly identify the source of the problem. (See the following example.)

One direct method for investigating the presence of nonconstant variance is available when there are replicated measurements on the response variable corresponding to a set of fixed values of the explanatory variables. For example, in the case of one explanatory variable, we may have

NUMERICAL METHODS FOR LEAST SQUARES PROBLEMS

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the above algorithm is numerically stable. The algorithm can be generalized in a straightforward way to rank deficient A and B. For details see Paige [627, 1979].

The algorithm above does not take advantage of any special structure the matrix B may have. If B has been obtained from the Cholesky factorization $W = BB^T$ it is of lower triangular form. In this case, and also when W is diagonal, it is advantageous to carry out the two QR decompositions in (4.3.19) and (4.3.21) together, maintaining the lower triangular form throughout. Paige [628, 1979] has given such a variation of the algorithm using a "zero chasing technique," with a careful sequencing of Givens transformations. With fast Givens rotations this requires a total of about $m^2n + 2mn^2 - 4n^3/3$ flops.

REMARK 4.3.2. In some applications, notably from interior point methods, one needs to solve a sequence of problems of the form (4.3.12), with A constant but $B = B_k$, $k = 1, \ldots, p$. The QR decomposition (4.3.19) can then be computed once and for all. In case $m = n$ this reduces the work for solving an additional problem from $5n^3/3$ to n^3.

4.4. Weighted Least Squares Problems

4.4.1. Introduction. In this section we consider the special linear model (4.3.1) where the components in the random error vector ϵ are uncorrelated. In this case the covariance matrix W is a positive diagonal matrix

$$W = \operatorname{diag}(w_1, w_2, \ldots, w_m) > 0.$$

The corresponding least squares problem, $\min_x (Ax - b)^T W^{-1}(Ax - b)$, can be written as a **weighted linear least squares problem**

$$\min_x \|D(Ax - b)\|_2, \tag{4.4.1}$$

where we have introduced the diagonal **weight matrix**

$$D = W^{-1/2} = \operatorname{diag}(d_1, d_2, \ldots, d_m).$$

In many cases it is possible to solve (4.4.1) as a standard linear least squares problem

$$\min_x \|\tilde{A}x - \tilde{b}\|_2, \quad \tilde{A} = DA, \quad \tilde{b} = Db.$$

However, in applications where the weights $d_1, \ldots, d_m$ vary widely in size this is not generally a numerically stable approach.

Note that the weight matrix in (4.4.1) is not unique. Therefore we will in the following assume that the matrix A has been row equilibrated, that is,

$$\max_{1 \le j \le n} |a_{ij}| = 1, \qquad i = 1, \ldots, m.$$

We also assume here and in the following that the rows of A are ordered so that the weights satisfy

$$\infty > d_1 \ge d_2 \ge \cdots \ge d_m > 0. \tag{4.4.2}$$

Then $d_1/d_m = \gamma \gg 1$ corresponds to the case when some components of the error vector in the linear model have much smaller variance than the rest, and we call such weighted problems **stiff**. Note that in the limit when some d_i tend to infinity, the corresponding ith equation becomes a linear constraint.

For stiff problems the condition number $\kappa(DA)$ will be large. An upper bound is given by

$$\kappa(DA) \le \kappa(D)\kappa(A) = \gamma\kappa(A).$$

It is important to note that this does *not* mean that the problem of computing x *from given data* $\{D, A, b\}$ *is ill-conditioned*. For the weighted problem (4.4.1) the perturbations in DA and Db will have a special form, and the normwise perturbation analysis given in Section 1.4.2 is not relevant; see Remark 1.4.3. However, that $\kappa(DA) \gg 1$ correctly warns us that special care may be needed in solving stiff weighted linear least squares problems.

REMARK 4.4.1. Problems with extremely ill-conditioned weight matrices arise, e.g., in electrical networks, certain classes of finite element problems, and interior point methods for constrained optimization. Vavasis [806, 1994] and Hough and Vavasis [474, 1994] have developed special methods for such applications, which satisfy a strong type of stability. ∎

It is easily seen that in general the method of normal equations is not well suited for solving stiff problems. To illustrate this, we consider the important special case where only the first p equations are weighted:

$$\min_x \left\| \begin{pmatrix} \gamma A_1 \\ A_2 \end{pmatrix} x - \begin{pmatrix} \gamma b_1 \\ b_2 \end{pmatrix} \right\|_2^2, \tag{4.4.3}$$

$A_1 \in \mathbf{R}^{p\times n}$ and $A_2 \in \mathbf{R}^{(m-p)\times n}$. Such problems occur, for example, when the method of weighting is used to solve least squares problems with the linear equality constraints $A_1 x = b_1$; see Section 5.1.4. For this problem the matrix of normal equations becomes

$$B = \begin{pmatrix} \gamma A_1^T & A_2^T \end{pmatrix} \begin{pmatrix} \gamma A_1 \\ A_2 \end{pmatrix} = \gamma^2 A_1^T A_1 + A_2^T A_2.$$

If $\gamma > u^{-1/2}$ (u is the unit roundoff) and $A_1^T A_1$ is dense, then $B = A^T A$ will be completely dominated by the first term and the data contained in A_2 may be lost. However, if the number p of very accurate observations is less than n, then the solution depends critically on the less precise data in A_2. (The matrix in Example 2.2.1 is of this type.) We conclude that for weighted least squares problems with $\gamma \gg 1$ the method of normal equations generally is not well behaved.

4.4.2. Methods based on Gaussian elimination. In Section 2.5 several methods based on a preliminary factorization by Gaussian elimination were discussed. In the Peters–Wilkinson method (see Section 2.5.1) A is first reduced by Gaussian elimination to upper triangular form. It was pointed out by Björck and Duff [104, 1980] that this method is suitable for weighted problems.

Assume that $\operatorname{rank}(A_1) = p$, and that p steps of Guassian elimination are performed on the weighted matrix $\tilde{A} = DA$ using row and column pivoting. Then the resulting factorization can be written

$$\Pi_1 \tilde{A} \Pi_2 = L_p D U_p, \tag{4.4.4}$$

where Π_1 and Π_2 are permutation matrices,

$$L_p = \begin{pmatrix} L_{11} & \\ L_{21} & L_{22} \end{pmatrix} \in \mathbf{R}^{m\times n}, \quad U_p = \begin{pmatrix} U_{11} & U_{12} \\ & I \end{pmatrix} \in \mathbf{R}^{n\times n},$$

$L_{11} \in \mathbf{R}^{p\times p}$ is unit lower triangular, and $U_{11} \in \mathbf{R}^{p\times p}$ unit upper triangular. Assuming that $\tilde{A}$ has full rank, D is nonsingular. Then (4.4.1) is equivalent to

$$\min_y \|L_p y - \Pi_1 \tilde{b}\|_2, \qquad U_p \Pi_2^T x = D^{-1} y.$$

This least squares problem is usually well-conditioned, since any ill-conditioning in $\tilde{A}$ is usually reflected in U. We illustrate the method in a simple example.

EXAMPLE 4.4.1. In Example 2.2.1 it was shown that the method of normal equations failed for the problem of Läuchli [517, 1961]. After multiplication with $\gamma = \epsilon^{-1}$ this becomes

$$A = \begin{pmatrix} \gamma & \gamma & \gamma \\ 1 & & \\ & 1 & \\ & & 1 \end{pmatrix}, \qquad b = \begin{pmatrix} \gamma \\ 0 \\ 0 \\ 0 \end{pmatrix},$$

which is of the form (4.4.3) with $p = 1$. After one step of Gaussian elimination we obtain the factorization $A = L_1 D_1 U_1$, where

$$L_1 = \begin{pmatrix} 1 & & \\ \gamma^{-1} & -1 & -1 \\ & 1 & \\ & & 1 \end{pmatrix}, \qquad D_1 U_1 = \begin{pmatrix} \gamma & \gamma & \gamma \\ & 1 & \\ & & 1 \end{pmatrix}.$$

It is easily verified that L_1 is well-conditioned, and the solution can be accurately obtained by solving $L_1^T L_1 y = L_1^T b$, and back-substitution $D_1 U_1 x = y$. ∎

In general, for a problem of the form (4.4.3) the LU factorization (4.4.4) will have the form

$$\begin{pmatrix} \gamma A_1 \\ A_2 \end{pmatrix} = \begin{pmatrix} L_{11} & \\ \frac{1}{\gamma} L_{21} & L_{22} \end{pmatrix} \begin{pmatrix} \gamma U_{11} & \gamma U_{12} \\ & I \end{pmatrix} \equiv L(DU), \tag{4.4.5}$$

where the blocks L_{ij} and U_{ij} are $O(1)$, and $L_{22} \in \mathbf{R}^{(m-p)\times(n-p)}$ is the reduced matrix. The normal equations for $y = (DU)x$ then equal $L^T L y = L^T b$, where

$$\begin{aligned} L^T L &= \begin{pmatrix} L_{11}^T L_{11} + \frac{1}{\gamma^2} L_{21}^T L_{21} & \frac{1}{\gamma} L_{21}^T L_{22} \\ \frac{1}{\gamma} L_{22}^T L_{21} & L_{22}^T L_{22} \end{pmatrix}, \\ L^T b &= \begin{pmatrix} \gamma L_{11}^T b_1 + \frac{1}{\gamma} L_{21}^T b_2 \\ L_{22}^T b_1 \end{pmatrix}. \end{aligned}$$

For $\gamma \gg 1$ the matrix $L^T L$ is almost block diagonal and its condition number is to first approximation independent of γ. If we let R_{11} and R_{22} be the Cholesky factors of $L_{11}^T L_{11}$ and $L_{22}^T L_{22}$, respectively, then the Cholesky factor of $L^T L$ will have the form

$$R = (1 + O(\gamma^{-2})) \begin{pmatrix} R_{11} & \frac{1}{\gamma}(L_{21}R_{11}^{-1})^T L_{22} \\ & R_{22} \end{pmatrix};$$

cf. Stewart [742, 1984]. After solving $RR^T y = L^T b$ the least squares solution is obtained from $DUx = y$, giving

$$x_2 = y_2, \qquad U_{11}x_1 = \frac{1}{\gamma} y_1 - U_{12} y_2.$$

For the weighted least squares problem the augmented system (4.3.16) has the form

$$\begin{pmatrix} \alpha W & A \\ A^T & 0 \end{pmatrix} \begin{pmatrix} \alpha^{-1} r \\ x \end{pmatrix} = \begin{pmatrix} b \\ 0 \end{pmatrix}, \tag{4.4.6}$$

where $W = D^{-2}$. The scaling factor α has been introduced for stability reasons; see Section 2.5.2. As before we assume that D has been chosen so that A is *row equilibrated*, which will tend to lower the condition of A. Further results on the prescaling of A before using the augmented system method are given in Duff [239, 1994]. The system can be solved by using the Bunch–Kaufman factorization described in Section 2.5.2. An advantage with this formulation is that linear constraints can be treated by letting $w_i = 0$ in (4.4.6).

A problem with this approach is that it is not easy to get an a priori estimate of the optimal value of α for stability. A second drawback with the method outlined in this section is that it works with a system of order $m + n$, which may be much larger than n. Therefore, the main use of this method seems to be for sparse problems, where the sparsity of the block I can be taken into account; see Arioli, Duff, and de Rijk [20, 1989].

4.4.3. QR decompositions for weighted problems. We now consider the use of methods based on the QR decomposition of A for solving weighted problems. We first examine the Householder QR method, and show by an example that this method can give poor accuracy for stiff problems unless the algorithm is extended to include *row interchanges*.

EXAMPLE 4.4.2. (See Powell and Reid [670, 1969].) Consider the problem $\min_x \|Ax - b\|_2$, where

$$A = \begin{pmatrix} 0 & 2 & 1 \\ \gamma & \gamma & 0 \\ \gamma & 0 & \gamma \\ 0 & 1 & 1 \end{pmatrix}, \qquad b = \begin{pmatrix} 2 \\ 2\gamma \\ 2\gamma \\ 2 \end{pmatrix},$$

with exact solution equal to $x = (1, 1, 1)$. Using exact arithmetic we obtain after the first step of QR decomposition of A by Householder transformations

(Algorithm 2.4.1) the reduced matrix

$$\tilde{A}^{(2)} = \begin{pmatrix} \frac{1}{2}\gamma - 2^{1/2} & -\frac{1}{2}\gamma - 2^{-1/2} \\ -\frac{1}{2}\gamma - 2^{1/2} & \frac{1}{2}\gamma - 2^{-1/2} \\ 1 & 1 \end{pmatrix}.$$

If $\gamma > u^{-1}$ the terms $-2^{1/2}$ and $-2^{-1/2}$ in the first and second rows are lost. However, this is equivalent to the loss of all information present in the first row of A. This loss is disastrous because the number of rows containing large elements is less than the number of components in x, so there is a substantial dependence of the solution x on the first row of A. (However, compared to the method of normal equations, which fails already when $\gamma > u^{-1/2}$, this is an improvement!) ∎

Van Loan [799, 1985] has given several examples illustrating that solving

$$\min_x \left\| \begin{pmatrix} A_2 \\ \gamma A_1 \end{pmatrix} x - \begin{pmatrix} b_2 \\ \gamma b_1 \end{pmatrix} \right\|_2^2 \tag{4.4.7}$$

instead of (4.4.3) with Householder will give bad accuracy for large values of γ.

It is also essential that *column pivoting* is performed when QR decomposition is used for weighted problems. Van Loan [799, 1985] gives an example of the form (4.4.3), where

$$A_1 = \begin{pmatrix} 1 & 1 & 1 \\ 1 & 1 & -1 \end{pmatrix},$$

to illustrate the need for column pivoting. Stability is lost here without column pivoting because the first two columns of the matrix A_1 are linearly dependent. When column pivoting is introduced this difficulty disappears.

Powell and Reid [670, 1969] extended the Householder algorithm to include *row interchanges*. In each step a pivot column is first selected in the reduced matrix, and then the element of largest absolute value in the pivot column is permuted to the top. Powell and Reid give an error analysis for this algorithm which shows that it has good stability properties for stiff problems as well.

It seems that there is no need to perform row pivoting in Householder QR, provided that the rows are sorted after decreasing row norm before the factorization, so that the weights satisfy (4.4.2). For example, if in Example 4.4.2 the two large rows are permuted to the top of the matrix A, then the Householder algorithm works well.

An approach related to that of Powell and Reid is taken by Gulliksson and Wedin [413, 1992]. They use scaled Householder transformations $\tilde{P}$ which are W invariant, i.e., satisfy

$$\tilde{P} W \tilde{P}^T = W = \operatorname{diag}(w_1, \ldots, w_m). \tag{4.4.8}$$

It is easy to verify that P must have the form

$$P = I - 2Wvv^T/(v^T W v), \qquad P^2 = I,$$

i.e., P is a reflector. Note that $W^{-1/2}PW^{1/2}$ is an orthogonal reflector.

A sequence of W invariant reflectors is used to transform $A\Pi$, where Π is a permutation matrix, to upper triangular form,

$$Q^T A\Pi = \begin{pmatrix} R \\ 0 \end{pmatrix}, \qquad Q^T = P_n \cdots P_2 P_1.$$

This is equivalent to the ordinary QR factorization

$$W^{-1/2}A\Pi = (W^{-1/2}QW^{1/2}) \begin{pmatrix} W^{-1/2}R \\ 0 \end{pmatrix}.$$

When $W > 0$ this method is equivalent to the algorithm of Powell and Reid. However, this approach generalizes simply to the case when W has the form $W = \operatorname{diag}(0, W_2)$, which corresponds to a constrained least squares problem. A backward error analysis of this method has been given by Gulliksson [410, 1995].

In contrast to the Householder QR method, the modified Gram–Schmidt (MGS) method is numerically invariant under row interchanges (except for effects deriving from different summation orders in the computed inner products). In particular, for problems of the special form (4.4.3) MGS will give accurate solutions independent of row ordering if γ is chosen optimally. However, as illustrated by the numerical results by Anda and Park [15, 1996], MGS will lose accuracy for very large values of γ. Gulliksson [411, 1995] has made a detailed study of the numerical stability of MGS for weighted problems.

Anda and Park [15, 1995] have studied the use of Givens QR algorithms for stiff least squares problems, and developed self-scaling fast plane rotations for such problems. They show that both fast and standard Givens rotations produce accurate results regardless of row sorting.

The following example from [15] illustrates the effect of row sorting in Givens rotation. Let $\gamma \gg 1$, and

$$A = \begin{pmatrix} a_{pp} & a_{pq} \\ \gamma a_{qp} & \gamma a_{qq} \end{pmatrix}, \qquad \bar{A} = \begin{pmatrix} \gamma \bar{a}_{pp} & \gamma \bar{a}_{pq} \\ \bar{a}_{qp} & \bar{a}_{qq} \end{pmatrix}.$$

The Givens transformations that zero the elements a'_{qp} and $\bar{a}'_{qp}$ in $A' = GA$, and $\bar{A}' = \bar{G}\bar{A}$, respectively, are (see (2.3.13))

$$G = \frac{1}{\sigma} \begin{pmatrix} a_{pp} & \gamma a_{qp} \\ -\gamma a_{qp} & a_{pp} \end{pmatrix}, \qquad \bar{G} = \frac{1}{\bar{\sigma}} \begin{pmatrix} \gamma \bar{a}_{pp} & \bar{a}_{qp} \\ -\bar{a}_{qp} & \gamma \bar{a}_{pp} \end{pmatrix},$$

where $\sigma = \sqrt{a_{pp}^2 + \gamma^2 a_{qp}^2}$ and $\bar{\sigma} = \sqrt{\gamma^2 \bar{a}_{pp}^2 + \bar{a}_{qp}^2}$. In each case the more heavily weighted row of the resulting matrix GA and $\bar{G}\bar{A}$ is in top position regardless of its initial position. Hence a sequence of rotations will move rows of large norms to the top of the matrix. The numerical results of Anda and Park also showed that the self-scaling rotations maintained high accuracy for extremely large values of γ. Their tests also showed no significant difference in accuracy between different rotation orderings.

Seelye Rebuttal Exhibit 5

Least-Squares Regression Based on Underlying Individual Unit Cost Data

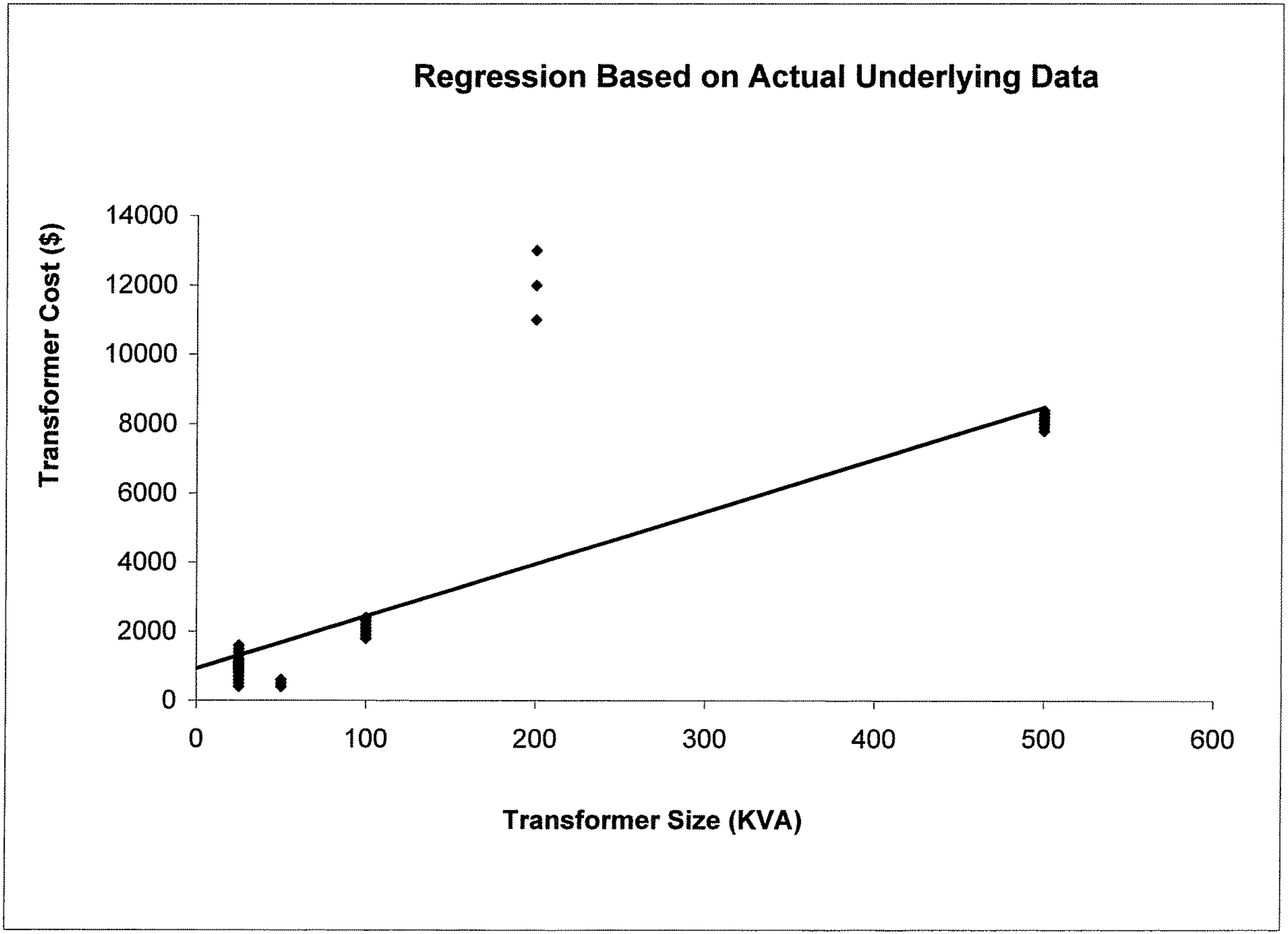
	Cost (y)	Size (x)
1	400	25
2	500	25
3	600	25
4	700	25
5	800	25
6	850	25
7	900	25
8	950	25
9	950	25
10	1000	25
11	1000	25
12	1050	25
13	1050	25
14	1100	25
15	1150	25
16	1200	25
17	1300	25
18	1400	25
19	1500	25
20	1600	25
21	400	50
22	500	50
23	600	50
24	1800	100
25	1800	100
26	1900	100
27	1900	100
28	2000	100
29	2000	100
30	2000	100
31	2100	100
32	2100	100
33	2100	100
34	2100	100
35	2100	100
36	2100	100
37	2200	100
38	2200	100
39	2200	100
40	2300	100
41	2300	100
42	2400	100
43	2400	100
44	11000	200
45	12000	200
46	13000	200

Least-Squares Regression Based on Underlying Individual Unit Cost Data

	Cost (y)	Size (x)
47	7800	500
48	7800	500
49	7900	500
50	7900	500
51	8000	500
52	8000	500
53	8000	500
54	8100	500
55	8100	500
56	8100	500
57	8100	500
58	8100	500
59	8100	500
60	8200	500
61	8200	500
62	8200	500
63	8300	500
64	8300	500
65	8400	500
66	8400	500

Least-Square Regression Results:

Intercept	929.97
Slope	15.10


Regression Based on Actual Underlying Data
Transformer Cost ($)
14000
12000
10000
8000
6000
4000
2000
0
0
100
200
300
400
500
600
Transformer Size (KVA)

Seelye Rebuttal Exhibit 6

Watkins' Methodology

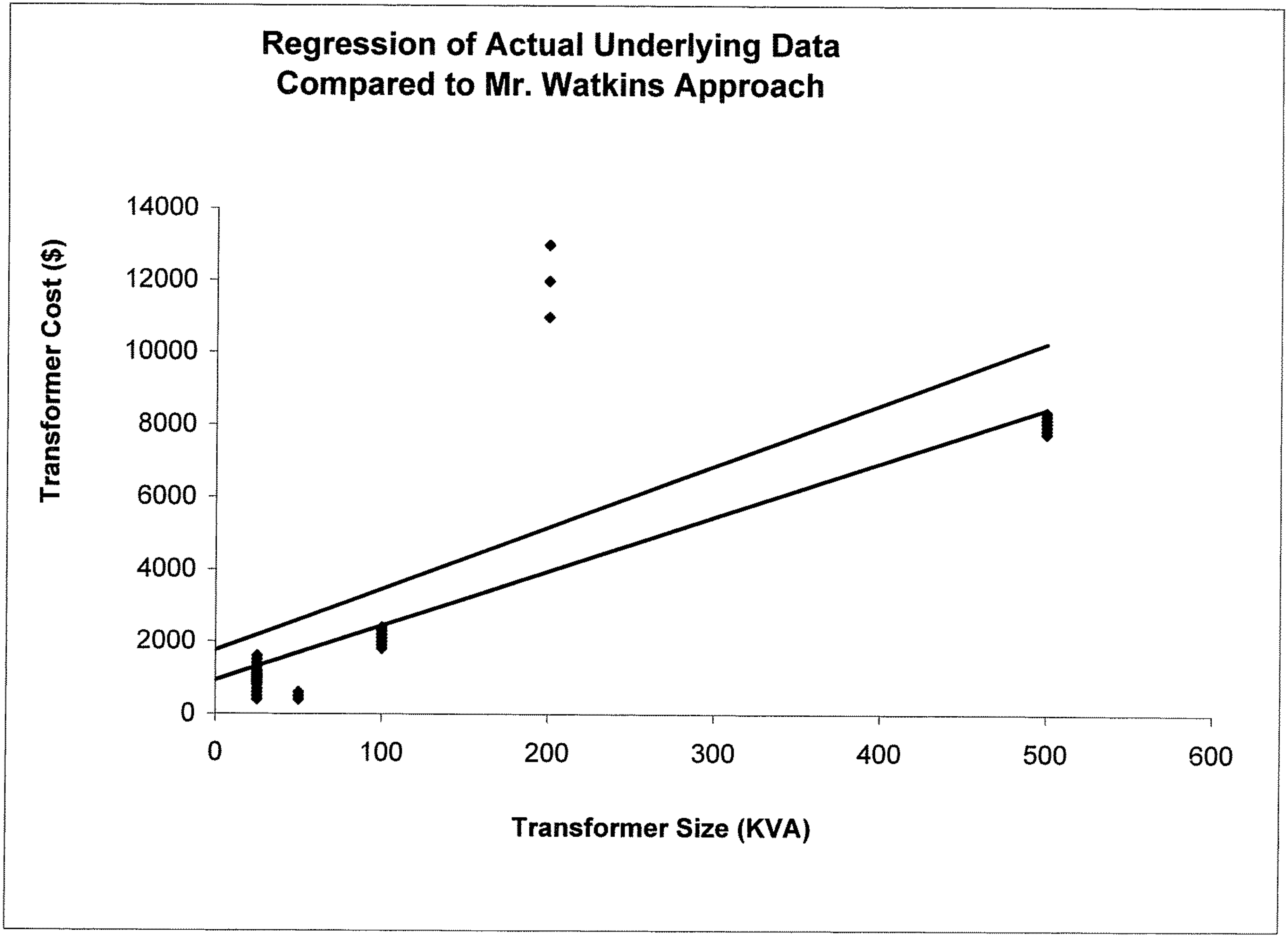
Unweighted Least-Squares Regression Applied to Summary Data

n	y	x	est y
20	1000	25	2177.5
3	500	50	2604.5833
20	2100	100	3458.75
3	12000	200	5167.0833
20	8100	500	10292.083

Unweighted Least-Squares Regression Results
Applied to Summary Data

Intercept	1,750.42
Slope	17.08

Watkins' methodology produces incorrect results


Regression of Actual Underlying Data
Compared to Mr. Watkins Approach
Transformer Cost ($)
14000
12000
10000
8000
6000
4000
2000
0
0
100
200
300
400
500
600
Transformer Size (KVA)

Seelye Rebuttal Exhibit 7

LG&E's Methodology

Weighted Least-Squares Regression Applied to Summary Data

n	y	x	y*n^.5	n^.5	xn^.5
20	1000	25	4472.136	4.47	111.8033989
3	500	50	866.0254	1.73	86.60254038
20	2100	100	9391.4855	4.47	447.2135955
3	12000	200	20784.61	1.73	346.4101615
20	8100	500	36224.301	4.47	2236.067977

Unweighted Least-Squares Regression Results
Applied to Summary Data

Intercept	929.97
Slope	15.10

Weighted least-squares regression produces correct results

Seelye Rebuttal Exhibit 8

Recalculation of Watkins' Customer Cost
Adding Back in Costs Classified as Customer Costs
In Watkins' Own Cost of Service Study
For Louisville Gas and Electric Company

		Residential	
Gross Plant			
364-365	Overhead Lines - Primary (Customer Cost)	$81,002,988	<<----Left Out By Watkins
364-365	Overhead Lines - Secondary (Customer Cost)	$17,478,480	<<----Left Out By Watkins
366-367	Underground Lines - Primary (Customer Cost)	$21.617,196	<<----Left Out By Watkins
366-367	Underground Lines - Secondary (Customer Cost)	$5.917,251	<<----Left Out By Watkins
368	Transformers - Power Pool (Customer Cost)	$24,900.009	<<----Left Out By Watkins
369	Services	$17,979,330	
370	Meters	$23,419,433	
	Total Gross Plant	$192,314,688	
Depreciation Reserve			
364-365	Overhead Lines - Primary (Customer Cost)	$41.305,089	<<----Left Out By Watkins
364-365	Overhead Lines - Secondary (Customer Cost)	$8,912,637	<<----Left Out By Watkins
366-367	Underground Lines - Primary (Customer Cost)	$11.023.053	<<----Left Out By Watkins
366-367	Underground Lines - Secondary (Customer Cost)	$3,017,328	<<----Left Out By Watkins
368	Transformers - Power Pool (Customer Cost)	$12,697,027	<<----Left Out By Watkins
369	Services	$9,168,030	
370	Meters	$11,942,050	
	Total Depreciation Reserve	$98.065,214	
Total Net Plant		$94,249,474	
Operation & Maintenance Expenses			
	Distribution Expense - Operating		
580	Operation Supervision & Engineering	$335,264	<<----Left Out By Watkins
583	Overhead Lines Expense	$1,539,816	<<----Left Out By Watkins
584	Underground Lines Expense	$76,825	<<----Left Out By Watkins
586	Meter Expense	$3,827,846	
587	Customer Installations Expense	-$54.914	
588	Misc Distribution Expense	$733.466	<<----Left Out By Watkins
589	Rents	$3,510	<<----Left Out By Watkins
590	Maintenance Supervision & Engineering	$2.664	<<----Left Out By Watkins
593	Maintenanceof Overhead Lines	$4,285,158	<<----Left Out By Watkins
594	Maintenance of Underground Lines	$268,665	<<----Left Out By Watkins
595	Maintenance of Line Transformers	$51,305	<<----Left Out By Watkins
598	Misc Distribution Expense	$65,224	<<----Left Out By Watkins
	Sub-total	$11,134,827	
	Customer Accounts Expense		
901	Supervision/Customer Accts	$529.663	<<----Left Out By Watkins
902	Meter Reading Expense	$1.702.884	
903	Records & Collections	$3,830,537	
904	Uncollectible Accounts	$682,801	<<----Left Out By Watkins
905	Misc Customer Accounts	$208,203	<<----Left Out By Watkins
	Sub-total	$6,954,087	
	Customer Service & Information Expense		
907	Supervision	$121,011	<<----Left Out By Watkins
908	Customer Assistance Expense	$3,638,581	<<----Left Out By Watkins
909	Informationational & Instruc	$287.718	<<----Left Out By Watkins
910	Misc Customer Service	$562.248	<<----Left Out By Watkins
913	Advertising Expense	$49.438	<<----Left Out By Watkins
916	Misc Sales Expense	$0	<<----Left Out By Watkins
	Sub-total	$4,658,996	

Recalculation of Watkins' Customer Cost
Adding Back in Costs Classified as Customer Costs
In Watkins' Cost of Service Study
For Louisville Gas and Electric Company

		Residential	
	General Expenses		
920	Admin & General Salaries	$898,681	**<<----Left Out By Watkins**
921	Office Supplies & Expenses	$444,790	**<<----Left Out By Watkins**
922	Administrative Expenses Transferred	-$128,927	**<<----Left Out By Watkins**
923	Outside Services Employed	$302,145	**<<----Left Out By Watkins**
924	Property Insurance	$198,131	**<<----Left Out By Watkins**
925	Injuries & Damages - Insurance	$145,672	**<<----Left Out By Watkins**
926	Employee Benefits	$1,495,956	**<<----Left Out By Watkins**
927	Franchise Requirements	$1,648	**<<----Left Out By Watkins**
928	Regulatory Commission Fees	$41,415	**<<----Left Out By Watkins**
929	Duplicate Charges - Cr	-$2,211	**<<----Left Out By Watkins**
930	Miscellaneous General Expense	$62,141	**<<----Left Out By Watkins**
931	Rents & Leases	$77,901	**<<----Left Out By Watkins**
935	Maintenance of General Plant	$306,824	**<<----Left Out By Watkins**
	Sub-total	$3,844,166	
	Total O & M Expenses	$26,592,077	
Depreciation Expense			
364-365	Overhead Lines - Primary	$2,712,284	**<<----Left Out By Watkins**
364-365	Overhead Lines - Secondary	$585,245	**<<----Left Out By Watkins**
366-367	Underground Lines - Primary	$723,825	**<<----Left Out By Watkins**
366-367	Underground Lines - Secondary	$198,132	**<<----Left Out By Watkins**
368	Transformers - Power Pool	$833,746	**<<----Left Out By Watkins**
369	Services	$602,015	
370	Meters	$784,171	
	Total Depreciation Expense	$6,439,418	

Revenue Requirement

	Residential		PCT	Cost	WGHT Cost
Interest	$2,309,112				
Equity return	$4,946,212				
Income Tax	$2,986,767				
Revenue For Return	10,242,091				
		Debt	47 52%	5 16%	2 45%
O & M Expenses	$26,592,077	Common	52 48%	10 00%	5 25%
Depreciation Expense	$6,439,418	Total	100 00%		7 70%
Total Customer Revenue Requirement	$43,273,585				
Number of Bills	4,301,388				
Monthly Cost	$10.06				