LG&E

an e·on company

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May 27, 2010

RE: ***Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates* – Case No. 2009-00549**

Dear Mr. DeRouen:

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

1. Rebuttal Testimony of S. Bradford Rives;
2. Rebuttal Testimony of Valerie L. Scott;
3. Rebuttal Testimony of Shannon L. Charnas;
4. Rebuttal Testimony of Ronald L. Miller;
5. Rebuttal Testimony of Daniel K. Arbough;
6. Rebuttal Testimony of William E. Avera;
7. Rebuttal Testimony of Lonnie E. Bellar;
8. Rebuttal Testimony of Robert M. Conroy;
9. Rebuttal Testimony of Butch Cockerill; and
10. Rebuttal Testimony 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

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. 2009-00549

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

Filed: May 27, 2010

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" or "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. What is the purpose of your testimony?

A. The purpose of my testimony is to address the consolidated tax adjustment proposal by Attorney General witness Michael Majoros, as well as his related interest synchronization adjustment.

Q. Do you agree with Mr. Majoros's recommendation to reflect consolidated income tax benefits in LG&E's income tax expense?

A. Absolutely not. This recommendation, if adopted, would represent a radical and abrupt departure from 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

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[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. 89-374, Order (May 25, 1990).

structure. The consummation of this transaction resulted in LG&E Energy Corp. 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*

[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. 89-374, Order at 20 (May 25, 1990).
[3] Corporate Policies and Guidelines for Intercompany Transactions (LG&E Holding) at 4-5.

an Agreement and Plan of Exchange and to Carry Out Certain Transactions in 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 there would be no cross-subsidization between unregulated activities and 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's and KU's reorganizations 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]

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[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. 89-374, 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).

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

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 a condition of approving 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,

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

> transfers and cost allocation to ensure and facilitate the full review by the Commission and protection against cross-subsidization.

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 of, or by, 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

[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).

providing utility service. In short, there should be a link or match between allowed income tax expense and regulatory utility service. The stand-alone method, emphatically approved by this Commission for the past twenty years, ensures this relationship by computing tax expense directly on test year revenues and costs and excluding the tax effects of revenue and expenses not associated with the provision of utility services.

Q. How does this compare with the AG's recommendation?

A. The AG's approach would abandon the Commission's time-tested stand-alone method of regulation. Under the AG'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 the AG's proposal confer a windfall benefit on the utilities' customers?

A. The tax benefits of the unregulated affiliate are the direct result of tax losses incurred by the unregulated business. Consistent with the procedure to insulate the regulated entities from all of the effects of unregulated operations, utility customers were not charged any of the costs that produced these tax losses. Because utility customers did not incur or pay for these losses, they should have no claim on the tax benefits they produced. The AG's proposal, however, would do just that: give customers the tax benefits of losses for which they did not pay or bear any risk.

The benefits of any tax losses produced by an unregulated affiliate belong to the owners of the affiliate who invested in that enterprise seeking potential gain, and at the risk of potential loss.

Q. Please explain what the benefits-burden relationship principle is, how the Commission has followed it in the past, and how the AG'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 produce the net operating losses are entitled to retain the associated tax 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 and, consequently, were not recovered through rates. They were, in fact, paid by shareholders.

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 these transactions, the

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[10] *In the Matter of: An Examination By the Public 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).

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 interest deduction). The AG's proposal would dramatically alter this historical balance.

Under the AG's consolidated approach, however, part of the shareholders' benefit for bearing the risk of its unregulated investments would be confiscated to reduce customers' rates.

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

A. 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. Imposing a consolidated tax adjustment ("CTA") creates a mathematical certainty that changes in the operations of unregulated affiliates will have the capacity to alter utility rates. If unregulated affiliate tax losses increase, utility rates will decrease. If unregulated affiliate tax losses decrease, utility rates will increase. Because the quantity of affiliate tax losses will depend directly on affiliate actions, the imposition of a CTA will drag the activities of unregulated affiliates into the regulatory arena, contrary to the long-standing principle of utility insulation. 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. Majoros's recommendation jeopardize the ability of LG&E and KU to achieve their authorized rates of return?**

A. Yes. Mr. Majoros'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 effect of the adjustment is to reduce revenues with 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 ability 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. The authors state:

> *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]

They further state:

> 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.
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> 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.
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> 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]

[11] Hahne and Aliff, Accounting for Public Utilities § 7.08[3].
[12] Hahne and Aliff, Accounting for Public Utilities § 17.06[3].

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 Company ("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 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.
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> ...
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> 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.[13]

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.

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:

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

> 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.[14]

Q. How, then, would you characterize the Commission's order in Case No. 2004-00103?

A. To my knowledge, the order in Case No. 2004-00103 represents the only instance in which the Commission has varied from its consistent application of the benefits and burdens principle. The Commission articulated a rationale for that lone departure -

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[14] *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).

and that rationale does not exist in this case. Consequently, the order does not represent relevant precedent in this proceeding.

Q. Should the Commission set aside the stand-alone tax methodology that has been in place for the past twenty 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 twenty 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. Is Kentucky's historical rejection of CTAs consistent with the practice that prevails throughout the regulatory jurisdictions of this country?

A. Absolutely. The vast preponderance of regulatory jurisdictions in this country do not impose CTAs, and recent decisions from other states' commissions do not indicate a trend favoring such adjustments. In a December 30, 2009 order rejecting a proposed CTA in a Delmarva Power and Light Company rate case, the Maryland Public Service Commission stated, "In order to adopt the Staff's recommended CTA, we would have to depart substantially from prior Commission decisions on this issue and join a very small minority of commissions."[15]

Even more recently, the Public Service Commission of the District of Columbia rejected a proposed CTA in its March 2, 2010 order in Potomac Electric Power Company's base rate case, noting that the stand-alone methodology is the majority approach: "[T]he Commission has decided to adhere to our traditional stand-alone approach regarding federal and district tax expense, which is widely followed by the majority of Commissions throughout the country."[16]

Virginia, the other jurisdiction in which LG&E's sister utility, KU, has significant operations, adopted as a matter of statutory law the "better and sounder policy" of using the stand-alone method. The Virginia legislature amended VA Code § 56-235.2 in 2007 to add the following language, which unambiguously endorses the stand-alone method:

> 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.[17]

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[15] *In the Matter of the Application of Delmarva Power and Light Company for an Increase in Its Retail Rates for the Distribution of Electric Energy*, Public Service Commission of Maryland Case No. 9192, Order No. 83085 at 22 (Dec. 30, 2009).
[16] *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, Public Service Commission of the District of Columbia Case No. 1076, Order No. 15710 at 92 (March 2, 2010).
[17] VA Code § 56-235.2(A).

In sum, there is no doubt that the CTA Mr. Majoros proposes is contrary to all of this Commission's precedent and is contrary to the stand-alone methodology embraced by the vast majority of other states' public utility commissions.

Q. How would rejecting Mr. Majoros's consolidated tax proposal impact any of his proposed adjustments (including his proposed interest synchronization adjustment) that are computed using LG&E's effective tax rate?

A. Obviously, Mr. Majoros's "effective tax rate" calculated on Exhibit MJM-1, Schedule 1.4.1 embodies his CTA. If this Commission rejects his proposal to reflect in utility rates the benefits of unregulated affiliate tax losses, then any of his other proposed adjustments that incorporate his proposed "effective tax rate" must be similarly rejected.

Q. Does this conclude your testimony?

A. Yes.

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VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **S. Bradford Rives**, being duly sworn, deposes and says that he is Chief Financial Officer for Louisville Gas and Electric Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that 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 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 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. <u>A distinct separation of costs between utility and non-utility activities will be maintained</u>.

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

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
<u>for Intercompany Transactions</u>

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.

<u>Policies and Guidelines</u>

1. <u>Separation of costs between utility and non-utility activities will be maintained</u>.

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. Intercompany transactions shall be structured to ensure that non-regulated activities are not subsidized by the regulated utility.

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 ITS ELECTRIC AND GAS BASE RATES	))))	CASE NO. 2009-00549

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

Filed: May 27, 2010

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 "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. What is the purpose of your testimony?

A. The purpose of my testimony is to address and respond to certain points and assertions made by intervenors to this proceeding. Specifically, I will address intervenors' comments on the following topics: (1) increase in labor costs due to recent union increases; (2) adjustment to pension, post retirement and post employment benefits; (3) the proposed amortization schedule for the 2008 Wind Storm and 2009 Winter Storm; and (4) CCS implementation costs.

Union Wage Increases

Q. Briefly explain the intervenors' objection to this proceeding.

A. Only one witness, Mr. Thomas J. Prisco, testifying on behalf of the Department of Defense and other federal executive agencies, objected to LG&E's adjustment to recognize an increase in labor costs due to an increase in union wages.[1] Mr. Prisco objected to the Company's adjustment because he alleged that the increased labor costs were incurred outside of the test period.[2] Although Mr. Prisco acknowledges that the amount of the increase is certain, he argues that the contract is not known and measurable because other variables, such as "increases in productivity, the number of

[1] Direct Testimony of Thomas J. Prisco of April 22, 2010 (Case No. 2009-00549) at 13-14.
[2] Id.

employees, [and] actual overtime" are not known.[3] Thus, the basis of Mr. Prisco's argument is that the wage increase is a post-test year adjustment that violates the matching principle because there was not an "offset for revenues"[4] to accompany the increase in expenses.

Q. Is the increase in union wage expenses a known and measurable expense?

A. Yes. As noted by Mr. Prisco, the contract was executed during the test year and went into effect November 16, 2009—a little over two weeks after the end of the test year. The increase in labor costs due to the union contract is certainly known and measurable as the 3.5% increase is a definite, quantitative increase. Further, the purpose of pro forma adjustments is to produce a revenue requirement that reflects the going forward level of expenses the Company will incur while the new rates are in effect. To ensure that the Company's revenue requirement is truly representative of going forward expenses, the increased labor costs arising from the union contract must be included.

Q. Does Mr. Prisco support other adjustments occurring outside of the test year?

A. Yes. Despite asserting that the increase in labor costs was inappropriate because the contract became effective shortly after the test year end, Mr. Prisco made an adjustment to reflect the Company's revised exhibit regarding pension, post retirement and post employment expenses.[5] Although these updated exhibits related to events occurring outside of the test year, Mr. Prisco accepted the adjustment merely because the adjustment lowered the Company's revenue requirement. Despite

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[3] Id.
[4] Id. at 14.
[5] Id. at 14-15.

accepting this adjustment, Mr. Prisco objected to the Company's adjustment for labor costs even though the contract giving rise to the increased labor costs was executed during the test year. Mr. Prisco has engaged in selective criticism concerning events he perceives to have occurred outside of the test year; only accepting those adjustments that lower the Company's revenue requirement. As Mr. Prisco's objection to the increased labor adjustment is inconsistent with his other adjustments and the union contract was executed during the test year, the Commission should accept the Company's adjustment as filed.

<u>**Pension, Post Retirement and Post Employment Benefits**</u>

Q. Briefly explain Mr. Prisco's and Mr. Kollen's adjustment to the Company's pension, post retirement and post employment benefits.

A. Mr. Prisco has accepted the Company's updated pension, post retirement and post employment benefits information, as the Company revised its expenses based on the results of the 2010 Mercer Study.[6] Further, Mr. Lane Kollen, who testified on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), also accepted this updated information.[7] The Company does not object to Mr. Prisco's and Mr. Kollen's acceptance of the Company's revised exhibit, in furtherance of the Commission's longstanding practice to require utilities to provide updated information throughout base rate proceedings. The Company presented revised revenue requirements, including updated pension, post retirement and post employment benefits information, in response to the Fourth Data Request of Commission Staff.

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[6] <u>Id</u> at 15.
[7] Direct Testimony of Lane Kollen of April 22, 2010 (Case No. 2008-00549) at 24-25.

2008 Wind Storm and 2009 Winter Storm Amortization

Q. Please explain Mr. Prisco's adjustment regarding amortization of the 2008 Wind Storm and 2009 Winter Storm.

A. Mr. Prisco objected to the length of the amortization schedule the Company proposed regarding recovery of the regulatory assets for the 2008 Wind Storm and 2009 Winter Storm.[8] Mr. Prisco stated that amortizing two significant storms over a five year period would constitute a burden on ratepayers.[9] As such, Mr. Prisco adjusted the amortization schedule for both regulatory assets to ten years, as opposed to the five years the Company had proposed.[10]

Q. Why did the Company utilize the five year amortization schedule?

A. When evaluating the appropriate amortization schedule to propose in this proceeding, the Company gave principal consideration to the Commission's previous storm damage recovery periods. Further, LG&E believes that the five year period strikes an appropriate balance between the need to lessen the near-term impact of the recovery with the desire to allocate costs to those who benefited from the Company's restoration efforts. Also, only operation and maintenance expenses will be amortized over a period of five years, as no capital expenditures were included in the regulatory assets established for the storm expenses. While the Company did incur significant capital costs, those expenditures will be subject to recovery over the useful life of those investments. For these reasons, LG&E objects to extending the amortization schedule in the manner Mr. Prisco has proposed.

[8] Direct Testimony of Thomas J. Prisco of April 22, 2010 (Case No. 2009-00549) at 8.
[9] Id.
[10] Id.

CCS Implementation Expense

Q. Briefly explain the intervenors' objection to including the CCS implementation expenses in the revenue requirement.

A. Mr. Kollen is the only witness who objected to the inclusion of this expense in the revenue requirement and proposed an adjustment to remove this expense from net operating income. Mr. Kollen argued that because the expenses were one-time implementation costs that were non-recurring, the Company should not be permitted to include the expenses in the revenue requirement.[11] Mr. Kollen instead posits that the "expenses are more akin to capital costs" and as an alternative to removing the items from the test year, "the Commission could direct that they be added to the capital costs of CCS."[12] Although CCS was implemented for both electric and gas customers, Mr. Kollen attributed all the implementation costs to the electric business.

Q. Should the CCS costs be removed from the calculation of the revenue requirement?

A. No. LG&E appropriately included $1.443 million in expenses related to the implementation of CCS in its net operating income and allocated 64% to the electric business and 36% to the gas business. While Mr. Kollen is correct that these expenses are non-recurring, these costs constitute reasonable and prudent expenditures that were necessary to implement the new customer service system. As these were reasonable and prudent expenditures wholly purposed upon implementing the new system, the Company should be permitted to recover its costs. Disallowing these costs from rates is arbitrary.

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[11] Direct Testimony of Lane Kollen of April 22, 2010 (Case No. 2009-00549) at 23-24.
[12] Id.

Q. Can the Company merely add the expenses to capital costs as Mr. Kollen has suggested?

A. No. In determining how to allocate CCS costs between expensed and capitalized accounts, LG&E adhered strictly to Generally Accepted Accounting Principles ("GAAP"). GAAP provides clear and detailed guidelines as to the type of expenditures that can be capitalized. Thus, the implementation costs for which the Company is currently seeking recovery cannot be capitalized as Mr. Kollen suggests, as the expenditures comprising the implementation costs can only be expensed and not capitalized pursuant to GAAP guidelines. All costs that could be capitalized have been booked accordingly.

Q. As the implementation costs cannot be capitalized, will the Company be able to recover those costs through another adjustment?

A. No. Unless the Commission permits the Company to recover the $1.443 million in prudently incurred implementation costs, the Company will be unable to recover these costs, as the expenses cannot be capitalized. In including these costs in the revenue requirement, the Company chose not to seek recovery of ongoing maintenance and support costs that have increased from previous levels because of the new software associated with CCS. These ongoing costs are greater than the one-time implementation costs. If recovery of the implementation costs is not permitted, the Company will then have to seek recovery of the ongoing maintenance and support costs. Scott Rebuttal Exhibit 1 contains an illustration comparing the one-time implementation costs to the ongoing maintenance and support costs.

Q. Would the Company consider amortizing the one-time implementation costs for a period longer than the one year it proposed?

A. Yes. If the Commission will not allow LG&E to recover all of the implementation costs in one year as proposed, there are more reasonable alternatives to Mr. Kollen's punitive proposal. First, the Company proposes an amortization period of three years as an alternative to not permitting any recovery, as the costs cannot be capitalized. Although the expense is non-recurring, the implementation costs were prudent and necessary. An amortization period lessens the immediate impact to ratepayers while allowing the Company to recover its costs for expenditures that were prudently incurred.

Secondly, if the Commission does not allow LG&E to recover all of the implementation costs in one year as proposed, it should allow the Company to recover the ongoing maintenance and support costs.

Q. Does this conclude your testimony?

A. Yes, it does.

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VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Valerie L. Scott**, being duly sworn, deposes and says that she is Controller for Louisville Gas and Electric Company and an employee of E.ON U.S. Services, Inc., and that she has personal knowledge of the matters set forth in the foregoing testimony, and that 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 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

Scott Rebuttal Exhibit 1

Louisville Gas & Electric Company
CCS Expenses

Category	Account	Estimated On-Going Expenses for CCS [1]	One-Time CCS Implementation Costs [2]	Difference	Electric Percent	Gas Percent	ELECTRIC One-Time CCS Implementation Costs	GAS One-Time CCS Implementation Costs
Incremental Labor								
	146	$ (12,198)	$ -	$ (12,198)			$ -	$ -
	903	(73,124)	-	(73,124)			-	-
	920	274,527	-	274,527			-	-
	935	552,854	-	552,854			-	-
Outside Services								
	910	-	1,357,229	(1,357,229)	64%	36%	868,627	488,602
	920, 921, 923	31,124	-	31,124			-	-
Non-Labor								
	910	-	83,042	(83,042)	64%	36%	53,147	29,895
	926	-	3,207	(3,207)	80%	20%	2,566	641
	935	1,243,881	-	1,243,881			-	-
TOTAL		**$ 2,017,064**	**$ 1,443,478**	**$ 573,586**			**$ 924,339**	**$ 519,139**

[1] See response to question 42(c) of the KIUC's first data request dated March 1, 2010.

[2] See response to question 42 (a) of the KIUC's first data request dated March 1, 2010 (excluding amounts charged to account 426, not included in net operating income).

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. 2009-00549

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

Filed: May 27, 2010

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 E.ON U.S. Services Inc., which provides services to Louisville Gas and Electric Company ("LG&E" or the "Company") and Kentucky Utilities Company ("KU") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address and respond to certain points and assertions made by intervenors to this proceeding. Specifically, I will address intervenors' comments on the following topics: (1) settlement payments from the United States Gypsum Corporation ("USGC") contract; (2) amortization of rate case expenses; (3) the calculation of injuries and damages; (4) recovery of expenditures from the 2008 Wind Storm and 2009 Winter Storm; (5) recovery of contributions to the Kentucky Consortium for Carbon Storage and the Carbon Management Resource Group; and (6) the change to International Financial Reporting Standards.

<u>Settlement Payments from the United States Gypsum Corporation</u>

Q. Briefly explain the intervenors' objections to this adjustment.

A. Mr. Thomas J. Prisco, testifying on behalf of the Department of Defense and other federal executive agencies, is the only intervenor that objected to this adjustment. Mr. Prisco appears to accept the Company's adjustment, but misunderstands the manner in which the calculation was performed. Mr. Prisco stated that if the settlement results in the elimination of non-recurring revenues and expenses, "there should be a downward adjustment to the expense section."[1]

Q. Do you agree with Mr. Prisco's position that there should be a downward adjustment in the expense section?

A. No. LG&E included an appropriate increase in expenses in its initial filing, as demonstrated by Rives Exhibit 1, Reference Schedule 1.34. Mr. Prisco appears to misunderstand the nature of the contract between LG&E and USGC. The agreement, as explained in my direct testimony, was a "take or pay" contract, under which USGC was required to reimburse LG&E for the expense of removing the gypsum, as well as an additional sum if USGC did not remove the gypsum. When USGC did not remove the gypsum, it reimbursed LG&E the costs of removing the gypsum; consequently, the Company reduced its expenses to reflect this USGC reimbursement. Further, as required under the contract, USGC paid the Company an additional sum for its failure to remove the gypsum, which was recorded as revenue. The Company reversed the impact of the reimbursement of expenses, as well as the increase in revenue, attributable to the USGC contract in determining its revenue requirement, as these amounts were non-recurring. Since the USGC contract has expired, LG&E will incur the gypsum cost in the future and will no longer have revenues from USGC under the contract. Mr. Prisco appears to believe that there should be a reduction in expenses to offset the reduction in revenue, which is a misunderstanding of the nature of the contract, as these amounts are not offsetting. The adjustments to net income are cumulative; they were merely recorded to two different accounts, one revenue and

[1] Direct Testimony of Mr. Thomas J. Prisco of April 22, 2010 (Case No. 2009-00549) at 17.

one expense. The Company properly included the correct amount of expenses in the revenue requirement in its initial filing.

Rate Case Expenses

Q. Briefly explain Mr. Prisco's objection to the amortization period the Company proposed for amortization of rate case expenses.

A. Mr. Prisco objected to LG&E's proposed amortization schedule for recovery of the expenses incurred in this proceeding, which, in accordance with well-established Commission precedent, is a three year period.[2] Mr. Prisco accepts that the Company should be permitted to recover its rate case expenses, while also acknowledging that the Commission has normally allowed LG&E to recover its expenses over a three year period.[3] Mr. Prisco's stated reason to deviate from this well-established practice is because the Company did not allow enough time to lapse between base rate proceedings.[4] He alternatively proposed a recovery period of five years.[5]

Q. Do you object to Mr. Prisco's proposed amortization schedule of five years?

A. Yes. As noted by Mr. Prisco, the three year amortization schedule for rate case expenses constitutes well-established Commission precedent. In addition to LG&E's past rate case proceedings, the Commission has permitted a three year recovery period in cases involving many other utilities since 1990.[6] Mr. Prisco has provided no quantitative reason to depart from the longstanding practice of amortizing rate case

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[2] Id. at 19.
[3] Id.
[4] Id.
[5] Id.
[6] See e.g., In the Matter of: Application of West Oldham Utilities, Inc., for a Rate Adjustment Pursuant to the Alternative Rate Filing Procedure for Small Utilities (Case No. 89-136) Order, February 16, 1990; In the Matter of: Proposed Adjustment of the Wholesale Water Service Rates of the City of Owenton, Kentucky (Case No. 98-283) Order, February 22, 1999; In the Matter of: Application of Kenergy Corporation for Review and Approval of Existing Rates (Case No. 2003-00165) Order, April 22, 2004.

expenses over a three year period, as he failed to allege that the expenses are imprudent or excessive. LG&E thus objects to his proposed lengthening of the recovery period and asks that the Commission permit the Company to amortize the rate case expenses in accordance with the established three year schedule.

Injuries and Damages

Q. Briefly explain Mr. Prisco's objection to the Company's calculation of Injuries and Damages.

A. While LG&E does not entirely understand Mr. Prisco's objection to the Company's calculation of Injuries and Damages, it appears that Mr. Prisco objects to the calculation not including the amount of expenses "being collected in base rates," presumably referring to the Injuries and Damages calculation from the Company's last base rate proceeding.[7] In responding to data requests, Mr. Prisco reiterated that he does not object to a normalization adjustment for Injuries and Damages. Mr. Prisco appears to not understand the values that go into the Injuries and Damages calculation; consequently, the adjustment he proposed does not make sense.

Q. Please explain how the Company calculated Injuries and Damages?

A. LG&E calculated Injuries and Damages in accordance with past practice. As Injuries and Damages are normalized over a ten-year period, the Company calculates the most recent ten-year average, compares that average to the amount incurred during the test year and then calculates the difference, which results in either a reduction or increase in the Company's expenses. This methodology has long been the Company's

[7] See Department of Defense's Response to LG&E 1-3.

practice and has been expressly approved by the Commission in prior rate cases.[8] Mr. Prisco has not provided any basis for departing from this long-standing calculation. As the calculation in this proceeding followed approved and well-established Commission precedent and Mr. Prisco has failed to provide any quantitative reason why the adjustment should not be accepted as LG&E has proposed, the Company respectfully requests that the Commission reject Mr. Prisco's adjustment.

<u>**Recovery of 2008 Wind Storm and 2009 Winter Storm Regulatory Assets**</u>

Q. Briefly explain the intervenors' objections to the Company's proposed rate recovery of the regulatory assets established for the operating and maintenance expenses incurred due to the 2008 Wind Storm and 2009 Winter Storm.

A. Mr. Michael J. Majoros, Jr., a witness testifying on behalf of the Attorney General, objected to the Company's proposed five-year amortization schedule for the Commission-authorized regulatory assets established for the operation and maintenance costs incurred during the 2008 Wind Storm and 2009 Winter Storm.[9] Mr. Majoros has posited that the Company should not be permitted to recover any of the costs from ratepayers, arguing instead that the Company should apply these costs to its accrued asset removal costs.[10]

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[8] <u>See</u> 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, June 30. 2004. In this order, the Commission expressly held that the Company's calculation was reasonable. The Company also utilized this methodology in its most recent base rate proceeding, 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). Also, the calculation is consistent with the Company's normalization adjustment for storm damages, which was utilized by the Company in its last several base proceedings as well.

[9] Direct Testimony of Michael J. Majoros of April 26, 2010 (Case No. 2009-00549) at 4.

[10] <u>Id.</u> at 5.

Q. Is it necessary that the Company be permitted to recover these expenses in this proceeding?

A. Yes. LG&E is seeking to recover $23.5 million and $43.9 million for the regulatory assets established for the 2008 Wind Storm and 2009 Winter Storm, respectively[11]. As demonstrated in the proceedings, in which Mr. Majoros indicated he did not participate,[12] in which the Commission permitted the Company to establish the regulatory assets, these amounts represent prudently incurred sums that were wholly purposed upon restoring service and repairing the unprecedented damage to the Company's transmission and distribution infrastructure.

Q. Can the Company apply the accrued asset removal costs to the regulatory assets in the manner Mr. Majoros is seeking?

A. No. The cost of removal funds can only be used in regard to capital assets. Mr. Majoros's proposition would require the Company to utilize cost of removal funds that can only be applied to capital assets to offset operating and maintenance costs. This is wholly inappropriate because the regulatory assets are solely comprised of operating and maintenance expenditures. Further, as a result of the 2008 Wind Storm and 2009 Winter Storm, the Company incurred costs related to replacement of capital assets, all of which were properly booked to the capital or cost of removal accounts. A chart illustrating the amounts booked to cost of removal accounts is attached as Charnas Rebuttal Exhibit 1. The information shown on this Exhibit is taken directly from the Company's general ledger. This Exhibit demonstrates that the Company has diligently recorded cost of removal charges as appropriate. Despite the clear division

[11] Reference Schedule 1.27 and 1.28 of Rives Exhibit 1.
[12] See Attorney General's Response to KPSC 1-1c.

between capital and operating and maintenance accounts, Mr. Majoros has asked the Commission to require the Company to violate a basic accounting principle in order to reduce the Company's accrued asset removal costs.

Q. Why does Mr. Majoros seek to reduce the Company's accrued asset removal costs?

A. Pursuant to Commission orders, LG&E collects amounts from ratepayers throughout the useful life of a capital asset so that the Company will have the funds necessary to remove the asset at the end of its useful life. The Company has only collected amounts that are approved by the Commission after sufficient investigation.[13] Mr. Majoros, in prior proceedings in which these amounts were being approved, has consistently argued that the Company is "overrecovering" for the future cost of removal.[14] Although this argument has been rejected each time it has been advanced, Mr. Majoros's current adjustment is the latest attempt to reduce the Company's accrued asset removal costs.[15]

Q. Is the Company over-recovering for asset removal costs?

A. Absolutely not. As mentioned above, the Company only collects amounts pursuant to Commission orders. Mr. Majoros incorrectly states in his testimony that because the asset removal account has an accrued balance, "LGE did not use it for its intended purposes" and that because the Company "continues to collect excess removal costs

[13] The Companies' depreciation rates were last approved in Case Nos. 2007-00564 and 2007-00565. Also, in Case No. 2009-00329, the Commission approved the depreciation rates for Trimble County Unit No. 2.

[14] For example, in the 2007 proceeding in which the Companies filed new depreciation studies, Mr. Majoros alleged that the Companies' computation of cost of removal had led to inflated recovery. See Direct Testimony of Michael J. Majoros, Jr. of May 12, 2008 (Case Nos. 2007-00564 and 2007-00565) at 17-18.

[15] For example, in Case Nos. 2003-00433 and 2003-00434, the Commission expressly rejected Majoros' argument that cost of removal should not be recovered over the life of an investment by including cost of removal as a component of depreciation rates. The Commission denied rehearing on the issue in its August 12, 2004 Order.

through the commission-approved depreciation rates....the regulatory liability will continue to grow."[16] This argument demonstrates that Mr. Majoros ignores the distinction between an *accrued* balance and an *excessive* balance. The Company has an accrued balance because the account is being accumulated such that when capital assets are retired and consequently removed, sufficient funds are available. Mr. Majoros seizes upon the fact that the account has an accrued balance to allege that the Company is overrecovering, while simultaneously admitting that the Company is adhering to Commission-approved depreciation rates. Mr. Majoros has continued to advance this baseless position in response to data requests in which he characterized the accrued balance as the Company's "debt to ratepayers."[17] This contention is both inaccurate and misleading. Quite simply, Mr. Majoros, although acknowledging that LG&E's asset removal balance has accumulated in accordance with approved rates, is asking the Commission to take the extraordinary step of requiring the Company to book operating and maintenance expenses to a capital account. In responding to data requests, Mr. Majoros was unable to provide a single authority—whether it be an accounting principle, Commission order, or court opinion—that approved applying an accrued asset removal account to storm restoration expenses.[18] Mr. Majoros has failed to provide any meaningful reason for such a departure from accounting principles and as such, LG&E respectfully requests that the Commission deny his adjustments.

[16] Direct Testimony of Michael J. Majoros of April 26, 2010 (Case No. 2009-00549) at 4.
[17] See Attorney General's Response to KPSC 1-1.
[18] See Attorney General's Response to LG&E 1-3.

Q. Does the Company agree with Mr. Majoros' contention that there is "no question" that LG&E will record the cost of removal regulatory liability in its "income account"?[19]

A. Absolutely not. LG&E cannot understand the basis for Mr. Majoros' contention that the Company will knowingly transfer funds from the cost of removal regulatory liability to its "income account". The Company has been quite clear that the accumulated cost of removal will be utilized for its intended purpose. Mr. Majoros' argument wrongly accuses the Company of having the intent for future deceitful misconduct. The Company takes its obligation to observe proper accounting practices very seriously; unsupported accusations such as Mr. Majoros' are unfounded.

KCCS and CMRG Regulatory Assets

Q. Briefly explain Mr. Majoros's objection to the Company recovering its contributions to the Kentucky Consortium for Carbon Storage ("KCCS") and the Carbon Management Resource Group ("CMRG").

A. Mr. Majoros has posited that LG&E should apply its cost of removal regulatory liability to the Commission-approved regulatory assets established for the Company's contributions to KCCS and CMRG.[20] Both KCCS and CMRG are local research endeavors purposed upon improving carbon storage in Kentucky produced as a result of coal-fired generation. Mr. Majoros provides no basis or support for his position, summarily asserting that "LGE should also apply those commission-approved

[19] See Attorney General's Response to KPSC 1-1.b.(4)
[20] Id. at 6.

regulatory assets to its Cost of Removal Regulatory Liability."[21] In responding to data requests, Mr. Majoros confirmed that he could not cite any authority supporting applying accrued asset removal funds to research contributions.[22] Furthermore, when questioned by the Staff related to his basis for applying regulatory assets for research endeavors, which have no relationship to the removal of assets, to the cost of removal regulatory liability, Mr. Majoros provided no valid explanation.[23]

Q. Should LG&E apply its cost of removal account to the KCCS and CMRG regulatory assets?

A. No, as Mr. Majoros's adjustment would again require the Company to apply costs booked as expenses to a capital asset, as LG&E considers contributions to be non-capital expenditures, since the contribution does not result in LG&E's ownership in any asset. Mr. Majoros's position is even more dubious with regard to these regulatory assets as contributions to research projects are intangible—there is certainly no cost of removal associated with a research investment. For the reasons discussed above pertaining to the 2008 Wind Storm and 2009 Winter Storm regulatory assets, it is improper to utilize a capital account for expenses. Further, LG&E is surprised that the Attorney General's witness would seek to disallow costs for clean coal research. The General Assembly has statutorily enacted a policy "to foster and encourage use of Kentucky coal by electric utilities serving the Commonwealth."[24] While LG&E has contributed to investments that improve carbon management in furtherance of the General Assembly's stated policy, the Attorney

[21] Id. at 6.
[22] See Attorney General's Response to LG&E 1-3.
[23] See Attorney General's Response to KPSC 1-2.
[24] KRS 278.020(1).

General's witness seeks to disallow these important expenditures for Kentucky. For these reasons, Mr. Majoros's adjustment should be denied.

International Financial Reporting Standards

Q. Briefly explain Mr. Majoros's objection regarding the International Financial Reporting Standards ("IFRS").

A. Mr. Majoros, in support of his position that the Company should be required to utilize its asset removal account for the regulatory assets, asserts that LG&E will soon begin utilizing IFRS, which are new accounting standards.[25] Mr. Majoros then stated that when LG&E adopts IFRS, the regulatory liability will be reduced to present value and transferred into the Company's equity account.[26]

Q. Does LG&E have a specified date on which it will adopt IFRS for regulatory accounting?

A. No. The Company does not currently have an implementation date for IFRS related to regulatory accounting. Further, LG&E does not believe that it can unilaterally adopt IFRS for its regulatory accounting until the Commission so orders. The Commission is statutorily authorized, pursuant to KRS 278.220, to establish a system of accounts for utilities and to prescribe the manner in which such accounts shall be kept. To the Company's knowledge, the Commission has not approved the use of IFRS for regulatory accounting. Further, the statute requires that the system of accounts for electric utilities "shall conform as nearly as practicable" to the system approved by the FERC.[27] To date, the FERC has neither adopted IFRS nor established a date by which IFRS will be approved. Also, the Securities and

[25] Direct Testimony of Michael J. Majoros of April 26, 2010 (Case No. 2009-00549) at 5.
[26] Id.
[27] KRS 278.220.

Exchange Commission, which has advocated for the financial reporting accounting standards IFRS contains, has made clear that it envisions 2015 as the earliest possible date for the required use of IFRS instead of GAAP reporting[28]. As such, Mr. Majoros's contention that LG&E is soon going to adopt IFRS is inaccurate, as LG&E has no present intention to adopt IFRS for its regulatory accounting until so authorized or directed by the Commission. Mr. Majoros's argument does not provide a valid basis for utilizing the asset removal regulatory liability for the regulatory assets as LG&E has no present timetable for implementing IFRS.

Q. Does this conclude your testimony?

A. Yes, it does.

[28] Per SEC release Nos. 33-9109 and 34-61578, *Commission Statement in Support of Convergence and Global Accounting* Standards, issued February 24, 2010, available at http://www.sec.gov/rules/other/2010/33-9109.pdf.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says that she is Director – Utility Accounting and Reporting for E.ON U.S. Services, Inc., and that she has personal knowledge of the matters set forth in the foregoing testimony, and that 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 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

Charnas Rebuttal Exhibit 1

Retirement Costs from Janaury 2009 Wind and Ice Storms

Louisville Gas & Electric Company

Account	Project	Task	Amount
108901	125722	1180154R02	$ 581.39
108901	125722	1398204R02	(95.06)
108901	125722	1406495R02	539.30
108901	125722	1407290R02	2,618.51
108901	125722	R	1,212,652.20
108901	125722	TOWER	22,416.55
108901	L8-2009	JANICE3832-R	118,820.74
108901	L8-2009	JANICE3855-R	1,276.29
108901	L8-2009	JANICE3862-R	7,060.11
108901	L8-2009	JANICE6620-R	12,179.24
108901	L8-2009	JANICE6661-R	4,464.71
108901	L8-2009	JANICE6662-R	13,996.35
108901	L8-2009	JANICE-6676-R	9,367.03
108901	L8-2009	JANICE6684-R	2,727.09
108901	L8-2009	JANICE6686-R	18,926.09
108901	L8-2009	JANICE6690.R	995.75
108901	STRMLGE	012709R	1,873,155.18
108901	STRMLGE	021109R	77,880.75
108901	LT8-2008	SEPTWIND.R-3809	19,052.84
108901	LT8-2008	SEPTWIND.R-6622	4,820.86
108901	LT8-2008	SEPTWIND.R-6624	2,427.09
108901	LT8-2008	SEPTWIND.R-6678	23,857.07
		TOTAL LG&E	$ 3,429,720.08

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS	**)**	
AND ELECTRIC COMPANY FOR AN	**)**	**CASE NO. 2009-00549**
ADJUSTMENT OF ITS ELECTRIC	**)**	
AND GAS BASE RATES	**)**	

REBUTTAL TESTIMONY OF
RONALD L. MILLER
DIRECTOR, CORPORATE TAX
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: May 27, 2010

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

A. My name is Ronald L. Miller. I am the Director of Corporate Tax for E.ON U.S. Services, Inc., which provides services to Louisville Gas and Electric Company ("LG&E" or "Company") and Kentucky Utilities Company ("KU") (collectively, "Companies"). 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 address and respond to certain points and assertions made by intervenors to this proceeding. Specifically, I will address intervenors' comments on the following topics: (1) removal of the Kentucky Coal Tax Credit; (2) the "Kentucky Clean Coal Incentive" tax credit; (3) the calculation of the Trimble County Unit No. 2's Advanced Coal Investment Tax Credit; and (4) errors in the intervenors' calculations.

<u>Kentucky Coal Tax Credit</u>

Q. Briefly explain the intervenors' objections to LG&E's removal of the Kentucky Coal Tax Credit.

A. Two intervenors objected to the removal of the Kentucky Coal Tax Credit from LG&E's property tax expense. Mr. Lane Kollen, testifying on behalf of the KIUC, objected to the Company's removal of the tax credit because the Company will be eligible for the credit through 2010.[1] Mr. Kollen argues that because LG&E will receive the credit in 2010, the credit is known and measurable.[2] He further attempts to characterize the adjustment as a post-test year adjustment.[3]

[1] Direct Testimony of Lane Kollen of April 22, 2010 (Case No. 2009-00549) at 26.
[2] <u>Id.</u> at 27-28.
[3] <u>Id.</u> at 28.

The other witness who objected was Mr. Thomas J. Prisco, who testified on behalf of the United States Department of Defense and other federal executive agencies. Mr. Prisco also alleged that the credit should not be removed because the Company will receive the credit in 2010.[4]

Q. Should the Company include the Kentucky Coal Tax Credit as a reduction to its property tax expense?

A. No. The purpose of pro forma adjustments is to produce a revenue requirement that accurately represents the going forward level of expenses and revenues. While both Mr. Kollen and Mr. Prisco admit the Kentucky Coal Tax Credit is expiring, neither witness provides any evidence suggesting that the credit will be legislatively extended. Further, the Company monitored the legislation discussed in the Kentucky General Assembly during the last legislative session and there was no activity regarding this statute. It is anticipated that the Kentucky Coal Tax Credit will sunset as scheduled, ending with coal purchases made in calendar-year 2009. Since this credit is expiring, it cannot be properly considered an ongoing credit. While the intervenors are correct that the Company received the credit during the test year, as the credit is expiring it is not a recurring reduction in expenses. Because the revenue requirement demonstrates the Company's going forward revenues and expenses, the elimination of the Kentucky Coal Tax credit was proper.

[4] Direct Testimony of Thomas J. Prisco of April 22, 2010 (Case No. 2009-00549) at 17.

Q. Briefly explain the intervenors' position regarding the "Kentucky Clean Coal Incentive" credit.

A. Mr. Kollen has asserted that if the Kentucky Coal Tax Credit is eliminated from the Company's calculation of its property tax expense, then the new "Kentucky Clean Coal Incentive" credit should be included.[5] This credit is pursuant to a 2005 statute enacted by the Kentucky General Assembly that provides a credit for Kentucky coal purchases for clean coal facilities beginning commercial operation after January 1, 2005. As explained in my direct testimony, the only LG&E facility that could potentially be eligible for the credit is Trimble County Unit No. 2, which has not yet begun commercial operation. Mr. Prisco has also alleged that the Company should include this new credit as a reduction to its tax expense.[6]

Q. Should the "Kentucky Clean Coal Incentive" credit be included in LG&E's calculation of its tax expense?

A. No, the "Kentucky Clean Coal Incentive" credit should not be included because the credit is neither known nor measurable, which is the standard for pro forma adjustments to the Company's calculation of its revenue requirement. While the Company has contacted the State, we have been informed that there is no application process in place at this time. Thus, there is no way of determining whether the facility in fact will be eligible.

Q. Has the Company taken any steps to apply for the credit?

A. Yes, the Company initially made informal inquiries with representatives of the state regarding the certification process. Since these initial informal inquiries, the

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[5] Direct Testimony of Lane Kollen of April 22, 2010 (Case No. 2009-00549) at 26.
[6] Direct Testimony of Thomas J. Prisco of April 22, 2010 (Case No. 2009-00549) at 17.

Company has subsequently written to the State of its intention on applying for the credit in anticipation of Trimble County Unit No. 2's impending commercial operation. However, because there is currently no existing regulation or certification process for applying, the Company does not know what credit, if any, it will be able to claim. Therefore, any adjustment to include this credit in the Company's revenue requirement is not appropriate because it is simply not known or measurable.

Q. Please discuss other uncertainties surrounding the "Kentucky Clean Coal Incentive" credit.

A. There are additional uncertainties associated with the "Kentucky Clean Coal Incentive" credit other than the current lack of a certification process. Another uncertainty is the amount of Kentucky coal that will be purchased for generation at Trimble County Unit No. 2. The KIUC, in its data request 2-8 to LG&E, asked the Company to provide the number of tons of coal that the Company will burn at Trimble County Unit No. 2 at an assumed 85% capacity factor. A copy of this data request and the Company's response is attached as Miller Rebuttal Exhibit 1. As noted in the Company's response, it is unclear at what capacity factor Trimble County Unit No. 2 will operate during its first few years of operation. Since the capacity factor is critical in determining the amount of coal purchased and burned, and of the credit, the amount of any credit to which the Company may be entitled cannot be reasonably estimated. This further demonstrates that the "Kentucky Clean Coal Incentive" credit is currently neither known nor measurable and thus should not be considered in calculating LG&E's tax expense.

Trimble County Unit No. 2 Advanced Coal Investment Tax Credit

Q. **Briefly explain Mr. Kollen's objection to LG&E's calculation of the Advanced Coal Investment Tax Credit ("ACITC").**

A. Mr. Kollen acknowledged that the Company discovered an inadvertent error regarding the book depreciation lives used to amortize the ACITC, which the Company brought to the intervenors' and Commission's attention in response to KPSC 2-47.[7] The error impacted Reference Schedules 1.45 and 1.46 of Rives Exhibit 1; Mr. Kollen's adjustment merely accepts the Company's revised calculation for Reference Schedule 1.45. LG&E does not object to this adjustment, but asserts that an adjustment to Reference Schedule 1.46 should be made as well, as Mr. Kollen omitted that correction. Further, Mr. Kollen neglected to apply the gross up revenue factor in determining the revenue requirement impact of the revised adjustments. LG&E believes that these corrections should be made as well. Mr. Kollen's revenue requirement reduction of $0.104 million on pages 4 and 31 of his testimony is incorrect. The correct revenue requirement impact is an increase of $0.262 million ($0.104 million decreased ACITC basis adjustment less the $0.268 million decrease in ITC amortization divided by 0.62521919 gross-up factor).

Errors in Intervenors' Calculations

Q. **Were there any other errors in the calculations the intervenors submitted in their direct testimony?**

A. Yes, there were errors that impact the intervenors' adjustments and calculation of the Company's revenue requirement. Mr. Kollen's calculation of the revenue

[7] Direct Testimony of Lane Kollen of April 22, 2010 (Case No. 2009-00549) at 31.

requirement impact of $2.637 million for the Kentucky Coal Tax Credit adjustment on pages 4 and 26 of his testimony is incorrect.[8] Specifically, Mr. Kollen did not reflect the loss of the federal income tax benefit as indicated in LG&E's response to KIUC 2-7. A copy of this data request and the Company's response is attached as Miller Rebuttal Exhibit 2. The correct revenue requirement impact of Mr. Kollen's adjustment for which the Company disagrees as discussed above is an increase of $2.055 million ($1.038 million increase in income tax expense less $0.363 million loss of federal income tax benefit @35% divided by 0.62521919 gross-up factor plus $0.977 million increase in property tax expense).

Also, Mr. Michael J. Majoros, Jr., testifying on behalf of the Attorney General, did not include the increased AG Federal and state income taxes amount in the Total adjustments (Line No. 51) or Adjusted Net Operating Income (Line No. 52) calculations of Exhibit MJM-1 and Exhibit MJM-3.[9] LG&E believes that the increase to AG Federal and state income taxes needs to be included in the spreadsheet formula to perform the AG's calculations correctly.

Q. Does this conclude your testimony?

A. Yes, it does.

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[8] Id. at 4, 26.
[9] Direct Testimony of Michael J. Majoros, Jr. of April 26, 2010 (Case No. 2009-00549) at Exhibit MJM-1, Exhibit MJM-3.

VERIFICATION

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

The undersigned, **Ronald L. Miller**, being duly sworn, deposes and says that he is Director – Corporate Tax for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Ronald L. Miller

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

Miller Rebuttal Exhibit 1

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2009-00549

Response to First Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 26, 2010

Question No. 8

Responding Witness: Paul W. Thompson/Ronald L. Miller

Q-8. Refer to the Company's response to KIUC 1-45.

a. Is there any reason the Company believes that it will not qualify for the $2 per ton credit for eligible Kentucky coal purchases for new clean coal facilities?

b. Will the coal used at TC2 be subject to the tax imposed under KRS 143.020 as referenced in KRS 141.428(1)(d)? If not, please explain why it will not be.

c. Is the Company or its parent subject to tax under KRS 136.120 as referenced in KRS 141.428(2)(a) and (b)? If not, please explain why it will not be.

d. Please describe the taxes imposed by: i) KRS 136.070, ii) KRS 136.120, and iii) KRS 141.020 or 141.040, and 141.041 as referenced in KRS 141.428(3)(a).

e. To the extent the Company qualifies for the $2 per ton credit for eligible Kentucky coal purchases for new clean coal facilities and the credit is applied to reduce the Company's Kentucky state income tax, please confirm that the Company agrees that the revenue requirement effect is the amount of the credit grossed-up for income taxes. If the Company does not agree with this statement, then please explain why it disagrees and provide a copy of all research and/or source documents upon which it relies for such disagreement.

f. Please provide the number of tons of coal that the Company will burn at TC2 at an 85% assumed capacity factor. Please provide all assumptions necessary to replicate the Company's quantification.

g. Please provide the Btu content of the coal that the Company will burn at TC2.

h. Please provide the projected heat rate of TC2.

A-8. a. As stated in the response to KIUC 1-45 b and c, the Kentucky Department of Energy and Environment has not formulated the qualification criteria or procedures for certification. Without knowing the criteria and procedures, qualification is not known at this time.

b. KRS 143.020 imposes a tax on the severance and/or processing of coal in the state of Kentucky. LG&E expects that Kentucky sourced coal used at TC2 will be subject to the severance tax imposed under KRS 143.020. The remaining coal purchased will originate outside of Kentucky and will not be subject to the tax imposed under KRS 143.020.

c. Yes, LG&E is subject to tax under KRS 136.120 which imposes state property taxes on operating property of public service corporations, including gas and electric power companies.

d. i) KRS 136.070 imposed a corporation license tax on corporations either having a commercial domicile in this state or foreign corporations owning or leasing property within the State of Kentucky. This tax ended for tax periods ending on 12/31/05 and later. As a public service corporation LG&E was not subject to the tax under KRS 136.070 prior to its expiration under KRS 136.0701.

ii) KRS 136.120 imposes state property taxes on operating property for public service corporations, including gas and electric power companies. LG&E is a public service corporation that is centrally assessed property taxes under KRS 136.120.

iii) KRS 141.020 is the imposition of Kentucky state income taxes on individuals. KRS 141.040 is the imposition of Kentucky income taxes on corporations. KRS 141.041 is the imposition of Kentucky limited liability entity taxes. LG&E is subject to KRS 141.040.

e. If LG&E receives the new clean coal incentive tax credit and if the credit were applied to reduce Kentucky income taxes, the revenue requirement effect of the state credit (less the loss of applicable federal tax benefit) would be grossed up for income taxes. However, LG&E has not applied for nor received the new clean coal incentive tax credit.

f. The Company does <u>not</u> anticipate operating TC2 at an 85% capacity factor, particularly in the first year of operation. The tons burned for total Trimble County 2 at an 85% capacity factor is estimated at 2,500,000 per year. That is based on 6,942 MMBTU per hour, an 85% capacity factor, and a BTU content per pound of 10,340. Therefore the BTU calculation is 6,942 X 24 hours X 365 days X 85% Capacity Factor X 1,000,000 = 51,690,132,000,000 BTU's.

BTU's per ton = 10,340 BTU's per pound X 2000 pounds = 20,680,000.

Tons per year = 51,690,132,000,000 divided by 20,680,000 = approx. 2,500,000.

Tons Calculated Above	2,500,000
Adjustment for 25% IMEA/IMPA ownership	0.75
KU/LG&E ownership tons	1,875,000
LG&E ownership percentage	0.19
LG&E tons	356,250
Estimated Kentucky Purchases	0.53
LG&E Kentucky purchases	188,813

g. The expected BTU content of the coal is 10,340 BTU per Pound.

h. The projected average net heat rate for the unit is 8,774 (BTU/kWh) for the year 2010, and 8,753 (BTU/kWh) for the year 2011.

Miller Rebuttal Exhibit 2

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2009-00549

Response to First Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 26, 2010

Question No. 7

Responding Witness: Ronald L. Miller

Q-7. Refer to the Company's response to KIUC 1-44(d). The question was addressed to the situation whereby the coal tax credit was applied to reduce the Kentucky state income tax. Please respond to the question that was asked.

A-7. The Company expects the 2009 coal tax credit that will be recognized in 2010 to be applied against the 2010 Property Tax. If the coal tax credit were applied to Kentucky state income tax, the state tax credit (less the loss of applicable federal tax benefit) would be grossed-up to quantify the revenue requirements.

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. 2009-00549

REBUTTAL TESTIMONY OF DANIEL K. ARBOUGH TREASURER LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: May 27, 2010

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

A. My name is Daniel K. Arbough. I am the Treasurer for Louisville Gas and Electric Company ("LG&E" or "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. What is the purpose of your testimony?

A. The purpose of my testimony is to address and respond to certain points and assertions made by intervenors to this proceeding. Specifically, I will address intervenors' comments on the following topics: (1) the adjustment for the interest rate swap involving Wachovia Bank, N.A.; (2) proposed adjustments to the Company's equity ratio; (3) LG&E's short-term debt; (4) LG&E's long-term debt; and (5) the cost of common equity to the Company.

<u>Interest Rate Swap with Wachovia Bank, N.A.</u>

Q. Briefly explain the intervenors' objections to this adjustment.

A. The Department of Defense, through its witness, Mr. Thomas J. Prisco, objected to the Company's adjustment to recover the costs associated with the termination of the interest swap agreement between LG&E and Wachovia Bank, N.A. ("Wachovia").[1] Mr. Prisco proposed limiting the Company's establishment of a regulatory asset for these costs to one-half of the termination fees.[2] Mr. Prisco's testimony in support of his adjustment implied that the interest swap transaction, as well as its subsequent termination, was imprudent.

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[1] Direct Testimony of Thomas J. Prisco of April 22, 2010 (Case No. 2009-00549) at 18.
[2] <u>Id.</u> at 19.

Q. Was LG&E's decision to enter into the interest rate swap agreement with Wachovia prudent?

A. Absolutely. As noted in my direct testimony, the Commission in Case No. 2003-00299, authorized the company to enter into an interest rate swap agreement with Wachovia in December 2003.[3] The purpose of the agreement was to protect the Company and its ratepayers from potentially volatile variable interest rates. Pursuant to the agreement LG&E paid Wachovia a fixed rate payment of 3.648%. This interest rate payment was significantly lower than the fixed interest rate payment the Company would have obtained through the issuance of a fixed rate bond, as fixed rate bond coupons were at 5% when the transaction was being considered. A copy of LG&E's application, which illustrates the prevailing coupon rates at the time the transaction was considered, is attached as Arbough Rebuttal Exhibit 1. Thus, LG&E's decision to enter into the transaction, which was authorized by the Commission, prudently permitted the Company to hedge the interest expense of variable rate bonds through obtaining fixed interest rate payments at a rate substantially below the market rate for fixed rate bond issuances.

Q. Why did the Company seek to convert some of its variable interest rates into fixed interest rate payments?

A. It has long been the Company's practice to maintain an appropriate balance of diversified debt, meaning that the Company strives to maintain mostly fixed interest rates, while also entering into a number of transactions containing variable interest rates. This practice allows the Company to hedge its risks, while providing financial

[3] Direct Testimony of Daniel K. Arbough of January 29, 2010 (Case No. 2009-00549) at 8.

advantages to the Company and its customers. At year-end 2009, 77% of LG&E's debt contained fixed interest rates, which is consistent with that of its sister company, KU, as 79% of its interest rates were fixed at year-end. A chart illustrating these balances is attached as Arbough Rebuttal Exhibit 2. The transaction with Wachovia was entered into in furtherance of sustaining this prudent balance.

Q. Did LG&E terminate the interest rate swap agreement?

A. No. Despite Mr. Prisco's contention that LG&E "deserve[s] some of the blame"[4] for the termination fees for which recovery is sought, LG&E neither terminated the agreement, nor possessed the ability to prohibit Wachovia from terminating the agreement. Quite simply, Wachovia exercised a contractual right based upon a standard term in the agreement. Thus any suggestions that the termination was imprudent are misplaced, as it was not the actions of LG&E that gave rise to the termination fees.

Q. Has termination of the agreement saved the Company and ratepayers interest expense?

A. Yes, and it continues to do so. Since the interest swap agreement was terminated in December of 2008 through May 4, 2010, the Company has saved $1,499.283.01. A chart demonstrating the savings, per month, is attached as Arbough Rebuttal Exhibit 3. This reduced interest expense was used in Rives Exhibit 2 to determine the Company's cost of debt. As the termination, although instigated by Wachovia, has reduced the Company's interest rate expense each month since it was terminated, it is unclear why Mr. Prisco has alleged that LG&E should only be permitted to establish

[4] Direct Testimony of Thomas J. Prisco of April 22, 2010 (Case No. 2009-00549) at 19.

half of its regulatory asset to better allocate "blame". Mr. Prisco has failed to demonstrate that entering into the Commission-authorized transaction was imprudent and has provided no proof that the termination has harmed ratepayers, as the savings from the termination are both substantial and continuing. Therefore, LG&E requests that the Commission deny Mr. Prisco's adjustment and permit the Company to establish a regulatory asset for all of its termination fees associated with the interest rate swap agreement.

Q. Was there an error in Mr. Prisco's calculation of his proposed adjustment?

A. Yes. Mr. Prisco's Exhibit 14 attempts to "reverse" half of the regulatory asset the Company is seeking by including that half in the Company's revenue requirement calculation.[5] Even if the Commission accepts Mr. Prisco's position, his calculation of the adjustment is incorrect. By adding half of the termination fees into the Company's revenue requirement, Mr. Prisco has assumed that the termination fees were "above the line" expenses, meaning that the expenses were included fully and directly in calculating LG&E's net income. This assumption is incorrect, as the termination fee (except for approximately $650,000 that was booked as interest expense) was booked to accounts that are "below the line," meaning that the items are not directly included in calculating the Company's revenue requirement. Thus, it was improper for Mr. Prisco to attempt to "reverse" half of the termination fee expense by altering the Company's revenue requirement, as he is reversing an accounting entry

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[5] See Direct Testimony of Thomas J. Prisco of April 22, 2010 (Case No. 2009-00549) at DOD/FEA Exhibit TJP-14.

that never existed. Also, this error affects Mr. Prisco's Exhibit 3, which is his calculation of the Company's revenue requirement.[6]

Capital Structure and Debt/Equity Ratio

Q. Briefly explain the adjustment the Attorney General's Witness, Dr. J. Randall Woolridge, made to the Company's capital structure.

A. Dr. Woolridge recommended a capital structure for LG&E of 50% debt and 50% equity, which varies from the Company's capital structure at the end of the test year, which consisted of 46.14% debt and 53.68% equity.[7] Dr. Woolridge's basis for this adjustment to LG&E's capital structure was his review of the capital structure ratios for Electric and Gas Proxy Groups.[8] His conclusion was that because the utilities in these groups tended to have a lower common equity ratio, LG&E was not currently exposed to enough financial risk.[9]

Q. Do you accept Dr. Woolridge's adjustment to the Company's capital structure?

A. No. Dr. Woolridge's analysis and recommendation ignores that the Company's capital structure is purposed upon achieving a rating in the "A" range, as defined by Standard & Poor's ("S&P") criteria. In May 2009, S&P revised its business and financial risk matrix structure, under which LG&E could obtain an "A-" rating by maintaining its current "Excellent" business risk profile and moving into the "Significant" category for its financial risk profile. A copy of the revised matrix and accompanying article is attached as Arbough Rebuttal Exhibit 4. Currently, LG&E is

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[6] See Direct Testimony of Thomas J. Prisco of April 22, 2010 (Case No. 2009-00549) at DOD/FEA Exhibit TJP-3.
[7] Direct Testimony of Bradford S. Rives of January 29, 2010 (Case No. 2009-00549) at Exhibit 2, Page 1 of 2.
[8] Direct Testimony of Dr. J. Randall Woolridge of April 22, 2010 (Case No. 2009-00549) at 13-14.
[9] Id.

in the "Aggressive" category, which has resulted in a BBB+ rating. In order to fall within the "Significant" financial risk profile, S&P's guidelines suggest that LG&E must maintain a debt to capital ratio of 45-50%, which results in a common equity of 50-55%. Note that these ratios are not calculated based on the financial statements as prepared using GAAP, but rather as adjusted by S&P. This is the reason the Company has maintained its equity ratio at its current level.

Q. How would Dr. Woolridge's recommendation for LG&E's capital structure impact its bond rating?

A. To achieve an "A-" rating, the Company needs to maintain its equity ratio, as adjusted by S&P, in the target range noted in my response above. LG&E's GAAP ratio was within the range at 54.19%, but its adjusted ratio was below this target range at the end of the test year at 49.18%. Dr. Woolridge's recommended capital structure would have the Company *decrease* its GAAP common equity to 50%, however. If the Commission accepts this adjustment to the capital structure, LG&E would, at best, remain at its current "BBB+" rating and in fact be at risk for a downgrade and thus higher interest expenses on its debt.

Q. Please explain the advantage of having an "A" rating, as opposed to "BBB" rating.

A. The recent financial crisis illustrated the advantages of having a rating in the "A" range, as well as the significant difference between an "A" and "BBB" rating. Attached as Arbough Rebuttal Exhibit 5 is an illustration which demonstrates the difference in bond spreads, which is the difference between the yield on a corporate bond and U.S. treasuries, between "A" and "BBB" utility corporate bonds during the recent economic downturn. During the height of the recession, the variance between "A" and "BBB" corporate bond yields grew significantly. Consequently, "BBB" rated utilities bonds were viewed as a significantly riskier investment. Although the divergence between "A" and "BBB" rated bond yields has narrowed as the economic situation improves, during volatile capital market conditions LG&E and its customers could face significantly higher interest expense if the Company fails to maintain its strong financial condition.

Q. Is LG&E's current equity ratio consistent with its prior capital structure?

A. Yes. Over the last ten years, LG&E's equity ratio has been very consistent. The equity ratio (including common and preferred stock, when applicable) during this period has ranged from 51.04% to 56.76%, as demonstrated by the Company's response to KPSC 1-3. This illustration demonstrates that the Company's common equity in the last decade has never been as low as the figure Dr. Woolridge has recommended. LG&E's consistency in its equity ratio is important, because, as discussed, significant reductions in a company's equity ratio places the business at risk to suffer a credit rating downgrade. Further, LG&E's capital structure has been consistent over the last ten years - during which two rate case proceedings have occurred - and there has been no adjustment to the Company's capital structure or its objective of obtaining a rating in the "A" range. In addition, when presented with an argument for a "hypothetical capital structure" in a prior ECR proceeding[10], the Commission rejected the argument stating that it "has never utilized or established a

[10] See 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, June 20, 2005.

hypothetical capital structure for the environmental surcharge" and it "utilizes the actual common equity ratio of the utility".[11] As the Company's capital structure is consistent and in keeping with its stated rating goals, LG&E respectfully requests that the Commission deny Dr. Woolridge's recommended capital structure, as the recommendation is not in the best financial interests of the Company or its ratepayers.

Short-Term Debt

Q. Briefly explain the adjustment that the KIUC's witness, Mr. Lane Kollen, made to LG&E's short-term debt.

A. Mr. Kollen added $100 million to LG&E's short-term debt, substantially altering the Company's capitalization at October 31, 2009.[12] Mr. Kollen's basis for this adjustment was that the Company's short-term debt was understated in its filing in this proceeding as compared to the amounts of short-term debt during the test year.[13] Further, Mr. Kollen asserted that utilities could intentionally alter their amount of short-term debt on any given day in order to increase their cost of capital and claimed revenue requirement.[14] In order to prevent what Mr. Kollen perceived as manipulation by LG&E, Mr. Kollen consequently imputed $100 million of short-term debt. Although Mr. Kollen advocated that the Commission should use a 13 month average to measure short-term debt, he did not use the 13 month average and instead imputed $100 million of short term debt, because the Company had stated in response to KIUC 2-10 that it was the Company's practice to keep short-term debt below $100 million.

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[11] Id. at 20.
[12] Direct Testimony of Lane Kollen (Case No. 2009-00549) at 35.
[13] Id. at 31.
[14] Id. at 34.

Q. Did LG&E manipulate its amount of short-term debt?

A. No. LG&E did not engage in manipulation regarding its amount of short-term debt. As explained in my direct testimony, the Company had a short-term debt balance of $150.7 million, which was eliminated by the $163.2 million of short-term debt that will become long-term debt when reacquired bonds are reissued. In anticipation of this event, LG&E's long-term debt was increased by $163.2 million. The $12.5 million difference between the actual short-term debt and the $163.2 million reduced the long-term debt and equity balances. Further, Mr. Kollen notes that the average daily balance of short-term debt by month during the test year was $162.824 million,[15] an amount very close to the $163.2 million in reacquired bonds that were held for the entire test period. The similarity in these amounts supports the zero balance of short-term debt contained in the filing, as it demonstrates the effect of the reacquired bonds on the short-term debt and further evinces that the Company did not engage in any type of manipulation in arriving at this amount.

Q. Is it fair to use the 13 month average as Mr. Kollen suggests?

A. No. Every figure contained in Rives Exhibit 2, which is the Company's capitalization at October 31, 2009, is based upon the amount *on that day.* The very title of the exhibit demonstrates that the capitalization worksheet captures the values on a single day. Mr. Kollen has suggested that the Company use a 13 month average for this one value, ignoring that the remainder of the exhibit would be calculated inconsistently. Mr. Kollen is urging this Commission to engage in selective averaging merely to reduce the Company's revenue requirement. Mr. Kollen has failed to provide the

[15] Id. at 32.

Commission with any basis for accepting this averaging concept, which is in contravention of well-established Commission precedent.

Q. Please comment on the effect of Mr. Kollen's adjustment regarding the short-term debt.

A. In addition to imputing $100 million to LG&E's short-term debt, Mr. Kollen reduced the Company's long-term debt and common equity on a pro rata basis.[16] This reduction in long-term debt and equity significantly altered the Company's capital structure, as the Company's equity was reduced to 51.49% from 53.86%.[17] As discussed above regarding Mr. Woolridge's adjustment to LG&E's equity ratio, reductions in the Company's equity ratio decrease the likelihood of LG&E obtaining a rating in the "A" range as defined by S&P. Even if the Commission accepts Mr. Kollen's position that some short-term debt should be imputed to LG&E, the adjustment should not be calculated in the manner in which Mr. Kollen has provided, as the calculation increases the leverage of the Company. Instead, the decrease in short-term debt should be offset completely by a reduction in long-term debt.

Cost of Short-Term and Long-Term Debt

Q. Briefly summarize Mr. Kollen's comments regarding the Company updating its cost of debt.

A. Mr. Kollen correctly observed that it is the Commission's longstanding practice to require utilities to provide updated information throughout base rate proceedings, including updating the cost of debt.[18] In accordance with this practice and pursuant to

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[16] Id. at 35.
[17] Id. at Exhibit LK-20, page 1 of 2.
[18] Id. at 36.

Commission discovery, LG&E updated its cost of short-term debt and long-term debt in updated responses to the KPSC 1-43. The Company does not object to Mr. Kollen's acceptance of this updated information.

<u>**Cost of Common Equity**</u>

Q. Please comment on Mr. Kollen's argument that the cost of common equity should be reduced.

A. This adjustment, principally asserted by another KIUC witness, Mr. Richard Baudino, is being addressed by Dr. William Avera's rebuttal testimony. I object to Mr. Baudino's and Mr. Kollen's adjustment for the reasons explained by Dr. Avera.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Louisville Gas and Electric Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough
Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

Arbough Rebuttal Exhibit 1

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

AUG 04 2003

IN THE MATTER OF THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ORDER AUTHORIZING THE ISSUANCE OF SECURITIES AND THE ASSUMPTION OF OBLIGATIONS	)))))	Case No. 2003-________

APPLICATION

Louisville Gas and Electric Company ("LG&E" or the "Company") hereby requests, pursuant to KRS 278.300, that the Commission authorize the issuance of securities, assumption of obligations and entrance into all necessary agreements and other documents relating thereto as more fully described herein. In support of this Application, LG&E states as follows:

1. The Company's full name is Louisville Gas and Electric Company. The post office address of the Company is 220 West Main Street, Louisville, Kentucky 40202. LG&E is a Kentucky corporation, a utility as defined by KRS 278.010(3)(a) and (b), and provides retail electric service to approximately 382,000 customers and retail gas service to approximately 310,000 customers in seventeen counties in Kentucky. A description of LG&E's properties is set out in Exhibit 1 to this Application. A certified copy of the Company's Articles of Incorporation was filed with the Commission in Case No. 2001-104 (The Joint Application of E.ON AG, Powergen plc, LG&E Energy Corp., Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of an Acquisition) and is incorporated herein.

2. This Application relates to the proposed refinancing of the Company's outstanding issues of County of Jefferson, Kentucky, Pollution Control Revenue Bonds (Louisville Gas and Electric Company Project), (i) 1993 Series B, due August 15, 2019, and (ii)

1993 Series C, due October 15, 2020, secured by LG&E's First Mortgage Bonds, Pollution Control Series V and W, respectively.

The existing Jefferson County Pollution Control Revenue Bonds 1993 Series B and 1993 Series C are herein sometimes referred to collectively as the "Existing Bonds". The existing LG&E First Mortgage Bonds, Pollution Control Series V and W are herein sometimes referred to collectively as the "Existing First Mortgage Bonds". LG&E was authorized to undertake its obligations in regard to the Existing Bonds and the Existing First Mortgage Bonds by Order of the Commission dated July 28, 1993, in Case No. 93-223. The County of Jefferson, Kentucky Pollution Control Revenue Bonds 1993 Series B and related LG&E First Mortgage Bonds, Pollution Control Series V were used to provide financing to refund the Jefferson County, Kentucky 6 1/8% 1978 Series A and the Jefferson County, Kentucky 6 3/8% 1978 Series A Pollution Control Revenue Bonds, authorized by the Commission in Case No. 7118, and the Jefferson County, Kentucky 6.60% 1979 Series A and the Jefferson County, Kentucky 1979 Series A 6.70% Pollution Control Revenue Bonds authorized by the Commission in Case No. 7546. The County of Jefferson, Kentucky Pollution Control Revenue Bonds 1993 Series C and related LG&E First Mortgage Bonds Series W were used to provide financing for refunding the Jefferson County, Kentucky 9 ¾% Pollution Control Revenue Bonds, 1984 Series A, authorized in Case No. 8802. All of the 1978, 1979 and 1984 Pollution Control Revenue Bonds and First Mortgage Bonds were used to provide financing, or to refund Bonds which provided financing, for a portion of the costs of acquiring, constructing, and installing certain air and water pollution control facilities and solid waste disposal facilities at LG&E's Cane Run and Mill Creek generating stations, and paying certain expenses in connection with the financing, as set out more particularly in the records of Case Nos. 7118, 7546, and 8802, which are incorporated by reference herein.

In connection with this refinancing, the Company requests authority to (i) assume certain obligations under various agreements relating to the refunding of the Existing Bonds in an aggregate principal amount not to exceed $128,000,000 and (ii) issue the Company's First Mortgage Bonds in an aggregate principal amount not to exceed $128,000,000 to collateralize the proposed new bonds all as more particularly described herein.

The purpose for refinancing the Existing Bonds is to take advantage of currently prevailing, historically low interest rates and thereby reduce LG&E's costs of debt over the life of the bonds. The Existing 1993 Series B and 1993 Series C Bonds currently bear interest at the rate of 5.625% and 5.45% per annum respectively. Based on current interest rates, the Company expects that Refunding Bonds (as hereinafter defined) could be issued initially at lower rates, whether variable or fixed, providing interest rate savings (see the net present value savings analysis attached hereto as Exhibit 2). The 1993 Series B and 1993 Series C Bonds also may be candidates for extension of maturity, which, if permissible, would preserve use of this tax-exempt funding source. LG&E is investigating whether, based upon factors including the remaining expected useful lives of the subject pollution control facilities, it will be possible to extend the maturity of the proposed Refunding Bonds, to a later date, which may not exceed 30 years from the issuance date of the Refunding Bonds. Any such extension would allow the continued use of low-cost tax-exempt financing beyond the current maturity of the Existing Bonds, further reducing costs. This low-cost tax-exempt financing directly benefits the Company's customers. While federal law does not presently permit new facility air and water pollution control financing on a tax-exempt basis, federal law does permit the issuance of pollution control bonds to refund outstanding pollution control bonds within 90 days prior to the redemption and discharge of the existing pollution control bonds and to extend the bond maturities within certain limits provided by applicable federal tax law. Such refunding issues may not exceed in principal amount the outstanding principal amount of pollution control revenue bonds being refunded.

The following table shows (i) the initial public offering price, (ii) proceeds to LG&E from the sale (after deducting underwriting discounts and commissions) and (iii) LG&E's expenses associated with the sale of the Existing Bonds:

	Public Offering Price	Proceeds	Expenses
County of Jefferson, Kentucky Pollution Control Revenue Bonds, 1993 Series B	$102,000,000	$101,694,000	$ 861,309
County of Jefferson, Kentucky Pollution Control Revenue Bonds, 1993 Series C	$26,000,000	$ 25,543,700	$ 58,759

The 1993 Series B Bonds are subject to redemption, upon at least thirty (30) days prior notice, at 102% of their principal amount beginning on August 15, 2003, through August 14, 2004. The 1993 Series C Bonds are subject to redemption, upon at least thirty (30) days prior notice, at 102% of their principal amount beginning on October 15, 2003, through October 14, 2004.

3. In November 2000, the voters of Jefferson County voted to consolidate the governmental and corporate functions of Jefferson County and the City of Louisville into a completely new form of government known as Louisville Jefferson County Metro Government ("Metro Government"). The Metro Government commenced operations on January 6, 2003 and replaced and supercedes the government of the prior County and City. The authorizing laws provide for mandatory assumption by the Metro Government of all existing contract obligations of the prior County and City and the Metro Government will accordingly be the issuer of the proposed refunding bond issues.

In connection with the refinancing of the Existing Bonds, LG&E would assume certain obligations under one or more loan agreements with the Metro Government and may enter into guaranty agreements guaranteeing repayment of all or any part of the obligations under the Refunding Bonds for the benefit of the holders of such bonds.

LG&E requests authority to assume certain obligations under various agreements in an aggregate principal amount not to exceed $128,000,000 in connection with the proposed issuance of one or more series of new Metro Government Pollution Control Revenue Bonds (the "Refunding Bonds"). The Metro Government has express statutory authority to issue the Refunding Bonds pursuant to KRS 103.220(5). LG&E proposes to assume such obligations in connection with the refinancing of the Existing Bonds. The proceeds of the Refunding Bonds would be loaned to LG&E by the Metro Government to provide funds to redeem and discharge the Existing Bonds, which would be carried out within 90 days of the issuance of the Refunding Bonds.

4. LG&E anticipates that the refinancing will employ LG&E's New First Mortgage Bonds (as hereinafter defined) to collateralize and secure the Refunding Bonds. LG&E's New First Mortgage Bonds would replace Existing First Mortgage Bonds, which presently secure the Existing Bonds. If LG&E's New First Mortgage Bonds are used, the structure and documentation for the issuance of the bonds and related agreements would be similar to the structure and documentation of other recent pollution control financings of LG&E approved by this Commission involving LG&E's First Mortgage Bonds. LG&E's New First Mortgage Bonds will be issued in like amount to the Refunding Bonds and would be used to secure its payment obligations under the Refunding Bonds. LG&E therefore requests authority to issue its New First Mortgage Bonds, Pollution Control Series (collectively the "New First Mortgage Bonds") in one or more series in an aggregate principal amount not to exceed $128,000,000 to carry out such collateralization. The New First Mortgage Bonds would be delivered to one or more

corporate trustees under indentures of trust between the Metro Government and such trustee (each a "Trustee"), in connection with the issuance and sale by the Metro Government of its Refunding Bonds. The New First Mortgage Bonds would be held by the Trustees to secure payment of the Refunding Bonds and payment by LG&E of all sums payable by LG&E as discussed below. The New First Mortgage Bonds will be issued pursuant to one or more supplemental indentures, each of which would be a supplement to the Trust Indenture dated November 1, 1949, between LG&E and BNY – Midwest Trust Company, as successor trustee, as heretofore amended and supplemented. The New First Mortgage Bonds would have a maturity date corresponding to the Refunding Bonds, not to exceed 30 years from date of issuance.

5. The Refunding Bonds would be issued pursuant to one or more indentures (each an "Indenture"), between the Metro Government and the Trustee. The proceeds from the sale of the Refunding Bonds would be loaned to LG&E pursuant to one or more loan agreements between the Metro Government and LG&E (collectively the "Loan Agreement").

The payments to be made by LG&E under the Loan Agreement for the Refunding Bonds, together with other funds available for the purpose, would be sufficient to pay the principal and interest on such Refunding Bonds. The Loan Agreement and the payments to be made by LG&E pursuant thereto will be assigned to the Metro Government to secure the payment of the principal and interest on the Refunding Bonds.

6. The Refunding Bonds would be sold in one or more underwritten public offerings, negotiated sales, or private placement transactions utilizing the proper documentation. Their price, maturity date(s), interest rate(s), redemption provisions and other terms and provisions of the Refunding Bonds (including, in the event all or a portion of the Refunding

Bonds initially bear a variable rate of interest, the method for determining the interest rate) would be determined on the basis of negotiations among LG&E, the Metro Government, and the purchasers of such bonds. However, the amount of compensation to be paid to underwriters for their services would not exceed two percent (2%) of the principal amount of the Refunding Bonds to be sold. Based upon past experience with similar refinancings, LG&E estimates the issuance costs, excluding underwriting fees for the Refunding Bonds, will be approximately $558,000.

7. Because of the historical spread between long-term fixed interest rates and short term rates, all or a portion of the Refunding Bonds may be issued initially with interest rates that fluctuate on a weekly, monthly or other basis as determined from time-to-time by LG&E, including issuance of auction mode Refunding Bonds, coupled with bond insurance. Depending on market conditions, fixed rate bonds for a portion of the financing may be issued. Fixed rate bonds would avoid increased exposure to interest rate fluctuations. LG&E would reserve the option to convert any variable rate Refunding Bonds at a later date to other interest rate modes, including a fixed rate of interest. Refunding Bonds that bear interest at a variable rate (the "Variable Rate Refunding Bonds") also may be issued subject to tender by the holders thereof for redemption or purchase. In order to provide funds to pay the purchase price of such tendered Variable Rate Refunding Bonds, LG&E would enter into one or more remarketing agreements with one or more remarketing agents whereby the remarketing agent would use its best efforts to remarket such tendered Variable Rate Refunding Bonds to other purchasers at a price equal to the purchase price of such Variable Rate Refunding Bonds, which will be 100% of the par amount of such Variable Rate Refunding Bonds. Thus, to the extent Variable Rate Refunding

Bonds are issued, the documentation will be similar to previous bonds that were issued with a variable interest rate.

8. Also, in the event that Variable Rate Refunding Bonds are issued, LG&E may enter into one or more liquidity facilities (the "Current Facility") with a bank or banks to be selected by LG&E (the "Bank"). The Current Facility would be a credit agreement designed to provide LG&E with immediately available funds with which to make payments with respect to any Variable Rate Refunding Bonds that have been tendered for purchase and not remarketed. The Current Facility is not expected to be pledged for the payment of the Variable Rate Refunding Bonds or to constitute security therefore. The Current Facility may consist in whole or in part of such liquidity facilities. Pursuant to the Current Facility, LG&E may be required to execute and deliver to the Bank a note evidencing LG&E's obligations to the Bank under the Current Facility.

In order to obtain terms and conditions more favorable to LG&E than those provided in the Current Facility or to provide for additional liquidity or credit support to enhance the marketability of the Variable Rate Refunding Bonds, LG&E may desire to be able to replace the Current Facility with (or to initially use) one or more substitute liquidity support and/or credit support facilities (the instrument providing the liquidity support and/or credit support and any subsequent replacement support facility thereof, including any replacement facility which replaces a replacement facility, is hereinafter referred to as a "Facility") with one or more banks, insurance companies (including municipal bond insurance companies) or other financial institutions to be selected by LG&E from time to time (each such financial institution hereinafter referred to as a "Facility Provider"). A Facility may be in the nature of a letter of credit, revolving credit agreement, standby credit agreement, bond purchase agreement, bond insurance or other similar arrangement designed to provide liquidity and/or credit support for the Variable Rate Refunding Bonds. It is contemplated that, in the event the Variable Rate Refunding Bonds are converted to bear interest at a fixed rate, the Current Facility (if not already replaced or terminated) or, if applicable, the Facility (unless earlier terminated) will be terminated in whole or in part following the date of conversion of such series of Variable Rate Refunding Bonds. The estimated cost of the refinancing shown in Section 6 does not include expenses incurred for entering into any Facility, however the impact on the overall cost of the refinancing would be approximately 25 basis points.

9. In connection with any Facility, LG&E may enter into one or more credit or similar agreements ("Credit Agreements") with the Facility Provider or providers of such facility, which would contain the terms of reimbursement or payment to be made by LG&E to the subject Facility Providers for amounts advanced by the Facility Providers under the particular Facility. Depending on the exact nature of a Facility, LG&E may be required to execute and deliver to the subject Facility Provider a promissory note (each such note hereinafter referred to as a "Facility Note") evidencing LG&E's repayment obligations to the Facility Provider under the related Credit Agreement; and the Trustee under the Indenture for the Variable Rate Refunding Bonds may be authorized, upon the terms set forth in such Indenture and any Credit Agreement, to draw upon the Facility for the purpose of paying the purchase price of Variable Rate Refunding Bonds tendered or required to be tendered for purchase in accordance with the terms of the Indenture which are not remarketed by the remarketing agent as provided in the remarketing agreement and/or for the purpose of paying accrued interest on the Variable Rate Refunding Bonds when due and paying principal, whether at maturity, upon redemption, acceleration or otherwise.

10. In connection with the issuance of the Refunding Bonds, LG&E may enter into one or more interest rate hedging agreements (including an interest rate cap, swap, collar or similar agreement, collectively the "Hedging Facility") with a bank or financial institution (the "Counterparty"). The Hedging Facility would be an interest rate agreement designed to allow LG&E to actively manage and to limit its exposure to variable interest rates or to manage its overall borrowing costs on any fixed rate Refunding Bonds. The Hedging Facility will set forth the specific terms upon which LG&E will agree to pay the Counterparty payments and/or fees for limiting its exposure to interest rates or lowering its fixed rate borrowing costs, and the other terms and conditions of any rights or obligations thereunder. The estimated cost of the refinancing does not include the costs of any Hedging Facility, which would be determined at the time of the hedge. However, based on current market conditions, the cost of a 3-year hedge would be approximately 130 basis points.

The terms of each Facility, each Credit Agreement, each Facility Note and each Hedging Facility would be negotiated by LG&E with the respective Bank, Facility Provider or Counterparty and would be the most favorable terms that can be negotiated by LG&E. The aggregate outstanding principal amount of the obligations of LG&E at any time under the Loan Agreement, and the Credit Facilities and related notes set forth in the immediately preceding sentence will not exceed the original aggregate principal amount of the Refunding Bonds (which will not exceed an aggregate principal amount of $128,000,000) plus accrued but unpaid interest and premium, if any, on such bonds.

11. No contracts have been made for the disposition of any of the securities which LG&E proposes to issue, or for the proceeds of such sale.

12. Attached as Exhibit 3 to this Application are copies of the pertinent sections of the official statements describing the redemption provisions for the Existing Bonds.

13. LG&E shall, as soon as reasonably practicable after the issuance of the Refunding Bonds referred to herein, file with the Commission a statement setting forth the date or dates of issuance of the securities, the price paid therefore, the interest rate(s) (and, if applicable, their method of determination), and all fees and expenses, including underwriting discounts or commissions or other compensation, involved in the issuance and distribution.

14. Exhibit 4 to this Application contains the financial exhibit required by 807 KAR 5:001, Section 11(2)(a), as described by 807 KAR 5:001, Section 6. It also contains information required by 807 KAR 5:001, Section 11(2)(b).

15. Exhibit 5 to this Application is a certified copy of LG&E's Board of Directors resolution authorizing the issuance of the First Mortgage Bonds, the assumption of obligations under the Loan Agreement, and all transactions related thereto and discussed in this Application.

16. Other requirements of the Commission's regulation regarding this Application, 807 KAR 5:001, Section 11, including (1)(b) regarding the amount and kind of notes, etc., and (1)(c) regarding the use to be made of the proceeds, have been supplied in the extensive discussion above in Sections 2 through 10 of this Application. Interest rates are at historically low levels. In order to take advantage of these levels and any further improvement of the capital markets, the Company respectfully requests that the Commission process this Application as expeditiously as practicable to afford the Company maximum flexibility in connection with this refinancing.

WHEREFORE, Louisville Gas and Electric Company respectfully requests that the Commission enter its Order, in the form of the Proposed Order attached as Exhibit 6, authorizing it to issue securities and to execute, deliver and perform the obligations of LG&E under the Loan Agreement, and any Remarketing Agreements, and Credit Agreements and the various Credit and Hedging Facilities and other documents and related notes set forth in this Application. Louisville Gas and Electric Company further requests that the order of the Commission specifically include provisions stating:

1. LG&E is authorized to issue and deliver the new First Mortgage Bonds in an aggregate principal amount not to exceed $128,000,000 in the manner set forth in its application.

2. LG&E is authorized to execute, deliver and perform the obligations of LG&E under, inter alia, the loan agreement(s) with the Metro Government, and under any remarketing agreements, hedging agreements, auction agreements, bond insurance agreements, credit agreements and facilities, and such other agreements and documents as set out in its application, and to perform the transactions contemplated by such agreements.

Respectfully submitted,

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Counsel for Louisville Gas and Electric Company

280576 v5

VERIFICATION

COMMONWEALTH OF KENTUCKY

COUNTY OF JEFFERSON

Daniel K. Arbough being first duly sworn, deposes and says that he is Treasurer for Louisville Gas and Electric Company, that he has read the foregoing Application and knows the contents thereof, and that the same is true of his own knowledge, except as to matters which are therein stated on information or belief, and that as to these matters, he believes them to be true.

Daniel K. Arbough

DANIEL K. ARBOUGH

Subscribed and sworn before me this 4th day of August, 2003.

My Commission Expires: 10/24/04

Sandra J. Watson

NOTARY PUBLIC, STATE AT LARGE

LOUISVILLE GAS AND ELECTRIC COMPANY
(807 KAR 5:001, Section 11, Item 1 (a))

A DESCRIPTION OF APPLICANT'S PROPERTY, INCLUDING A STATEMENT OF THE NET ORIGINAL COST OF THE PROPERTY AND THE COST THEREOF TO APPLICANT

MARCH 31, 2003

The applicant owns and operates thermal-electric generating units with an aggregate station rating totaling 2,881,000 Kw. This total consists of 2,434,000 Kw of steam generation capacity and 447,000 Kw of combustion turbine peaking units. The applicant also owns an 80,000 Kw hydroelectric generating station, the operation of which is affected by the water level and flow of the Ohio River.

The applicant's electric transmission system includes substation capacity of approximately 11,519,700 Kva and approximately 656 pole miles of lines, and is interconnected with the systems of neighboring utilities.

The applicant operates underground gas storage facilities with a current working gas capacity of approximately 15.1 billion cubic feet used for seasonal and peak-day augmentation of winter pipe line supply.

The applicant's gas transmission system includes 212 miles of transmission mains, and the gas distribution system includes 4,066 miles of distribution mains.

Other properties include an office building, service centers, warehouses, garages, and other structures and equipment, the use of which is common to both the Electric and Gas Lines of Business.

The net original cost of the property and cost thereof to the applicant at March 31, 2003, was:

	Electric	Gas	Common	Total
Original Cost	$ 3,043,033,720	$ 462,518,018	$ 183,374,323	$ 3,688,926,061
Less Reserve for Depreciation	$ 1,247,091,470	$ 161,412,610	$ 77,111,739	$ 1,485,615,819
Net Original Cost	$ 1,795,942,250	$ 301,105,408	$ 106,262,584	$ 2,203,310,242
Allocation of Common To Electric and Gas	$ 79,696,938	$ 26,565,646	$ (106,262,584)	$ -
Total	$ 1,875,639,188	$ 327,671,054	$ -	$ 2,203,310,242

LOUISVILLE GAS & ELECTRIC COMPANY
Debt Refunding Analysis

Jefferson County $102 million due August 15, 2019
Comparison: Fixed
Impact on Cash Flow

		REFUNDING - FIXED				REFUNDING W/EXTENSION						PRESENT VALUE ANALYSIS		
		TAX EXEMPT POLLUTION CONTROL BONDS				TAX EXEMPT POLLUTION CONTROL BONDS								
Date	Principal Outstanding	Interest @ 5.6250%	Debt Expense Amortization (1)	Taxes (2)	Total Cash Outlay	Interest @ 5.10%	Debt Expense Amortization (2)	Call Premium	Issue Expenses	Taxes (2)	Total Cash Outlay	Periodic (Cost) or SAVINGS from Refunding	Present Value Factor	Present Value SAVINGS
15-Aug-03	$102,000,000							$2,040,000	$945,000		2,985,000	($2,985,000)	1.0000	($2,985,000)
15-Feb-04	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.9849	152,103
15-Aug-04	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.9701	149,811
15-Feb-05	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.9555	147,552
15-Aug-05	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.9411	145,328
15-Feb-06	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.9269	143,138
15-Aug-06	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.9129	140,980
15-Feb-07	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.8991	138,855
15-Aug-07	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.8856	136,762
15-Feb-08	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.8722	134,700
15-Aug-08	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.8591	132,670
15-Feb-09	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.8461	130,670
15-Aug-09	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.8334	128,701
15-Feb-10	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.8208	126,761
15-Aug-10	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.8084	124,850
15-Feb-11	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.7963	122,968
15-Aug-11	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.7843	121,114
15-Feb-12	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.7724	119,289
15-Aug-12	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.7608	117,491
15-Feb-13	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.7493	115,720
15-Aug-13	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.7380	113,975
15-Feb-14	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.7269	112,257
15-Aug-14	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.7160	110,565
15-Feb-15	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.7052	108,899
15-Aug-15	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.6945	107,257
15-Feb-16	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.6841	105,640
15-Aug-16	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.6737	104,048
15-Feb-17	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.6636	102,480
15-Aug-17	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.6536	100,935
15-Feb-18	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.6437	99,413
15-Aug-18	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.6340	97,915
15-Feb-19	$102,000,000	2,868,750	61,613	(1,182,768)	1,685,982	2,601,000	48,610			(1,069,449)	1,531,551	$154,431	0.6245	96,439
15-Aug-19	$102,000,000	2,868,750	61,613	(1,182,768)	103,685,982	2,601,000	48,610			(1,069,449)	103,531,551	$154,431	0.6151	94,985
	TOTAL	$91,800,000	$1,971,617	($37,848,568)	$155,851,431	$83,232,000	$1,555,529	$2,040,000	$945,000	($34,222,366)	$153,994,634	$1,956,797		$898,271

(1) Debt Amortization Expense includes issuing costs of new series and remaining unamortized debt expense of the old series
(2) Tax calculation based on interest expense and the amortization of new issue debt expense.

01-Aug-03

NOTE: This analysis is based on current rates which have risen significantly in last few weeks - Refinancing would only be completed if economics are attractive following approval by the commission.

Jefferson County $102 million due August 15, 2019
Comparison: Fixed
Assumptions

EXISTING ISSUE
Jefferson Co. Pollution Control Bonds

	5.625%	$ 102,000,000	Matures August 15, 2019
Unamortized Debt Expense		$1,971,617	At April 30, 2003
Remaining amortization period			
From Aug. 15, 2003 to Maturity		192.0	months
Assuming 14 Year Extension		360.0	months
Redemption (Call) Price		102%	FIRST CALL August 15, 2003
Amount of Premium		$2,040,000	
Cost of Funds (Lost Investment Earnings)	[redacted]		

PROPOSED REFUNDING
Tax Exempt Pollution Control Bonds

	5.100%	$ 102,000,000	Matures August 15, 2019

Bond Issue Costs			0.93%
Underwriting		0.65%	
Bond Counsel	$	78,000.00	0.08%
Company Counsel	$	70,000.00	0.07%
Underwriters Couns	$	42,000.00	0.04%
Ratings	$	30,000.00	0.03%
Printing	$	6,000.00	0.01%
Trustee Counsel	$	6,000.00	0.01%
Accountants	$	40,000.00	0.04%
Trustee	$	6,000.00	0.01%
FMB Trustee	$	4,000.00	0.00%
AMT			0.00%
Issuance costs		282,000	0.28%

MISCELLANEOUS

Tax rate	40.363%
Discount rate	3.04%

LOUISVILLE GAS & ELECTRIC COMPANY
Debt Refunding Analysis

Jefferson County $102 million due August 15, 2019
Comparison: Fixed
Impact on Cash Flow

REFUNDING - FIXED — TAX EXEMPT POLLUTION CONTROL BONDS

Date	Principal Outstanding	Interest @ 5.6250%	Debt Expense Amortization (1)	Taxes (2)	Total Cash Outlay
15-Aug-03	$ 102,000,000				
15-Feb-04	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-04	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-05	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-05	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-06	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-06	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-07	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-07	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-08	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-08	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-09	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-09	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-10	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-10	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-11	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-11	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-12	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-12	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-13	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-13	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-14	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-14	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-15	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-15	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-16	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-16	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-17	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-17	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-18	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-18	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Feb-19	$ 102,000,000	2,868,750	61,613	(1,182,768)	1,685,982
15-Aug-19	$ 102,000,000	2,868,750	61,613	(1,182,768)	103,685,982
TOTAL		$91,800,000	$1,971,617	($37,848,569)	$155,951,431

REFUNDING W/EXTENSION — TAX EXEMPT POLLUTION CONTROL BONDS

Date	Interest @ 4.80%	Debt Expense Amortization (2)	Call Premium	Issue Expenses	Taxes (2)	Total Cash Outlay
15-Aug-03			$2,040,000	$945,000		2,985,000
15-Feb-04	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-04	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-05	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-05	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-06	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-06	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-07	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-07	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-08	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-08	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-09	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-09	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-10	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-10	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-11	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-11	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-12	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-12	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-13	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-13	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-14	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-14	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-15	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-15	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-16	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-16	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-17	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-17	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-18	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-18	2,448,000	48,610			(1,007,694)	1,440,306
15-Feb-19	2,448,000	48,610			(1,007,694)	1,440,306
15-Aug-19	2,448,000	48,610			(1,007,694)	103,440,306
TOTAL	$78,336,000	$1,555,529	$2,040,000	$945,000	($32,246,218)	$161,074,782

PRESENT VALUE ANALYSIS

Date	Periodic (Cost) or SAVINGS from Refunding	Present Value Factor	Present Value SAVINGS
15-Aug-03	($2,985,000)	1.0000	($2,985,000)
15-Feb-04	$245,677	0.9858	242,189
15-Aug-04	$245,677	0.9718	238,752
15-Feb-05	$245,677	0.9580	235,363
15-Aug-05	$245,677	0.9444	232,022
15-Feb-06	$245,677	0.9310	228,729
15-Aug-06	$245,677	0.9178	225,482
15-Feb-07	$245,677	0.9048	222,281
15-Aug-07	$245,677	0.8919	219,126
15-Feb-08	$245,677	0.8793	216,016
15-Aug-08	$245,677	0.8668	212,950
15-Feb-09	$245,677	0.8545	209,927
15-Aug-09	$245,677	0.8424	206,947
15-Feb-10	$245,677	0.8304	204,010
15-Aug-10	$245,677	0.8186	201,114
15-Feb-11	$245,677	0.8070	198,259
15-Aug-11	$245,677	0.7955	195,446
15-Feb-12	$245,677	0.7842	192,671
15-Aug-12	$245,677	0.7731	189,936
15-Feb-13	$245,677	0.7621	187,240
15-Aug-13	$245,677	0.7513	184,583
15-Feb-14	$245,677	0.7407	181,963
15-Aug-14	$245,677	0.7301	179,380
15-Feb-15	$245,677	0.7198	176,834
15-Aug-15	$245,677	0.7096	174,324
15-Feb-16	$245,677	0.6995	171,849
15-Aug-16	$245,677	0.6896	169,410
15-Feb-17	$245,677	0.6798	167,005
15-Aug-17	$245,677	0.6701	164,635
15-Feb-18	$245,677	0.6606	162,298
15-Aug-18	$245,677	0.6512	159,994
15-Feb-19	$245,677	0.6420	157,723
15-Aug-19	$245,677	0.6329	155,484
TOTAL	$4,876,649		$3,278,941

(1) Debt Amortization Expense includes issuing costs of new series and remaining unamortized debt expense of the old series
(2) Tax calculation based on interest expense and the amortization of new issue debt expense.

01-Aug-03

NOTE: This analysis is based on rates in early July - Refinancing will be completed only if economics are attractive following approval by the commission.

Jefferson County $102 million due August 15, 2019
Comparison: Fixed
Assumptions

EXISTING ISSUE
Jefferson Co. Pollution Control Bonds
5.625% ########## Matures August 15, 2019

Unamortized Debt Expense $1,971,617 At April 30, 2003

Remaining amortization period

From Aug. 15, 2003 to Matu	192.0	months
Assuming 14 Year Extension	360.0	months

Redemption (Call) Price 102% FIRST CALL August 15, 2003
Amount of Premium $2,040,000

Cost of Funds (Lost Investment Earnings)
[illegible]

PROPOSED REFUNDING
Tax Exempt Pollution Control Bonds
4.800% ########## Matures August 15, 2019

Bond Issue Costs			0.93%
Underwritii		0.65%	
Bond Counsel	$	78,000.00	0.08%
Company Cour	$	70,000.00	0.07%
Underwriters C	$	42,000.00	0.04%
Ratings	$	30,000.00	0.03%
Printing	$	6,000.00	0.01%
Trustee Couns	$	6,000.00	0.01%
Accountants	$	40,000.00	0.04%
Trustee	$	6,000.00	0.01%
FMB Trustee	$	4,000.00	0.00%
AMT			0.00%
Issuance c		282,000	0.28%

MISCELLANEOUS
Tax rate 40.363%

Discount rate 2.86%

LOUISVILLE GAS & ELECTRIC COMPANY
Debt Refunding Analysis

Jefferson County $26 million due October 15, 2020
Comparison: Fixed
Impact on Cash Flow

	EXISTING CAPITALIZATION					PROPOSED REFUNDING						PRESENT VALUE ANALYSIS		
	TAX EXEMPT POLLUTION CONTROL BONDS					TAX EXEMPT POLLUTION CONTROL BONDS								
Date	Principal Outstanding	Interest @ 5.450%	Debt Expense Amortization	Taxes	Total Cash Outlay	Interest @ 5.10%	Debt Expense Amortization (1)	Call Premium	Issue Expenses	Taxes (2)	Total Cash Outlay	Periodic (Cost) or SAVINGS from Refunding	Present Value Factor	Present Value SAVINGS
15-Oct-03	$ 26,000,000							$520,000	$445,000		965,000	($965,000)	1.0000	($965,000)
15-Apr-04	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.9849	31,929
15-Oct-04	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.9701	31,448
15-Apr-05	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.9555	30,974
15-Oct-05	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.9411	30,507
15-Apr-06	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.9269	30,047
15-Oct-06	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.9129	29,594
15-Apr-07	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.8991	29,148
15-Oct-07	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.8856	28,709
15-Apr-08	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.8722	28,276
15-Oct-08	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.8591	27,850
15-Apr-09	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.8461	27,430
15-Oct-09	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.8334	27,017
15-Apr-10	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.8208	26,609
15-Oct-10	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.8084	26,208
15-Apr-11	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.7963	25,813
15-Oct-11	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.7843	25,424
15-Apr-12	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.7724	25,041
15-Oct-12	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.7608	24,663
15-Apr-13	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.7493	24,292
15-Oct-13	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.7380	23,926
15-Apr-14	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.7269	23,565
15-Oct-14	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.7160	23,210
15-Apr-15	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.7052	22,860
15-Oct-15	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.6945	22,516
15-Apr-16	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.6841	22,176
15-Oct-16	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.6737	21,841
15-Apr-17	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.6636	21,512
15-Oct-17	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.6536	21,188
15-Apr-18	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.6437	20,869
15-Oct-18	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.6340	20,554
15-Apr-19	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.6245	20,244
15-Oct-19	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.6151	19,939
15-Apr-20	26,000,000	708,500	37,334	(301,037)	407,463	663,000	50,422			(287,955)	375,045	32,418	0.6058	19,639
15-Oct-20	26,000,000	708,500	37,334	(301,037)	26,407,463	663,000	50,422			(287,955)	26,375,045	32,418	0.5967	19,342
TOTAL		$24,089,000	$1,269,348	($10,235,263)	$39,853,737	$22,542,000	$1,714,348	$520,000	$445,000	($9,780,468)	$39,716,532	$137,205		($110,643)

(1) Debt Amortization Expense includes issuing costs of new series and remaining unamortized debt expense of the old series
(2) Tax calculation based on interest expense and the amortization of new issue debt expense.

NOTE: This analysis is based on current rates which have risen significantly in last few weeks - Refinancing would only be completed if economics are attractive following approval by the commission.

Jefferson County $26 million due October 15, 2020
Comparison: Fixed
Assumptions

EXISTING ISSUE

Jefferson Co. Pollution Control Bonds

	5.450%	$ 26,000,000	Matures October 15, 2020
Unamortized Debt Expense		$1,269,348	At April 30, 2003
Remaining amortization period			
From Aug. 15, 2003 to Maturity		204.0	months
Assuming 13 Year Extension		360.0	months
Redemption (Call) Price		102%	FIRST CALL October 15, 2003
Amount of Premium		$520,000	
Cost of Funds (Lost Investment Earnings)	[illegible]		

PROPOSED REFUNDING

Tax Exempt Pollution Control Bonds

	5.100%	$ 26,000,000	Matures October 15, 2020

Bond Issue Costs			1.71%
Underwriting		0.65%	
Bond Counsel	$	78,000.00	0.30%
Company Counsel	$	70,000.00	0.27%
Underwriters Coun	$	42,000.00	0.16%
Ratings	$	24,000.00	0.09%
Printing	$	6,000.00	0.02%
Trustee Counsel	$	6,000.00	0.02%
Accountants	$	40,000.00	0.15%
AMT	$	-	0.00%
Trustee	$	6,000.00	0.02%
FMB Trustee	$	4,000.00	0.02%
Issuance costs		276,000	1.06%

MISCELLANEOUS

Tax rate	40.363%
Discount rate	3.04%

LOUISVILLE GAS & ELECTRIC COMPANY
Debt Refunding Analysis

Jefferson County $26 million due October 15, 2020
Comparison: Fixed
Impact on Cash Flow

	EXISTING CAPITALIZATION					PROPOSED REFUNDING						PRESENT VALUE ANA	
	TAX EXEMPT POLLUTION CONTROL BONDS					TAX EXEMPT POLLUTION CONTROL BONDS							
Date	Principal Outstanding	Interest @ 5.450%	Debt Expense Amortization	Taxes	Total Cash Outlay	Interest @ 4.80%	Debt Expense Amortization (1)	Call Premium	Issue Expenses	Taxes (2)	Total Cash Outlay	Periodic (Cost) or SAVINGS from Refunding	Present Value Factor
15-Oct-03	$ 26,000,000							$520,000	$445,000		965,000	($965,000)	1.0000
15-Apr-04	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.9858
15-Oct-04	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.9718
15-Apr-05	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.9580
15-Oct-05	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.9444
15-Apr-06	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.9310
15-Oct-06	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.9178
15-Apr-07	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.9048
15-Oct-07	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.8919
15-Apr-08	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.8793
15-Oct-08	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.8668
15-Apr-09	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.8545
15-Oct-09	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.8424
15-Apr-10	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.8304
15-Oct-10	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.8186
15-Apr-11	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.8070
15-Oct-11	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.7955
15-Apr-12	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.7842
15-Oct-12	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.7731
15-Apr-13	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.7621
15-Oct-13	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.7513
15-Apr-14	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.7407
15-Oct-14	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.7301
15-Apr-15	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.7198
15-Oct-15	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.7096
15-Apr-16	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.6995
15-Oct-16	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.6896
15-Apr-17	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.6798
15-Oct-17	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.6701
15-Apr-18	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.6606
15-Oct-18	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.6512
15-Apr-19	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.6420
15-Oct-19	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.6329
15-Apr-20	26,000,000	708,500	37,334	(301,037)	407,463	624,000	50,422			(272,214)	351,786	55,676	0.6238
15-Oct-20	26,000,000	708,500	37,334	(301,037)	26,407,463	624,000	50,422			(272,214)	26,351,786	55,676	0.6150
	TOTAL	$24,089,000	$1,269,348	($10,235,263)	$39,863,737	$21,216,000	$1,714,348	$520,000	$445,000	($9,256,262)	$38,925,738	$927,998	

(1) Debt Amortization Expense includes issuing costs of new series and remaining unamortized debt expense of the old series
(2) Tax calculation based on interest expense and the amortization of new issue debt expense.

NOTE: This analysis is based on rates in early July - Refinancing will be completed only if economics are attractive following approval by the commission.

Jefferson County $26 million due October 15, 2020
Comparison: Fixed
Assumptions

E X I S T I N G   I S S U E

Jefferson Co. Pollution Control Bonds

	5.450%	$ 26,000,000	Matures October 15, 2020
Unamortized Debt Expense		$1,269,348	At April 30, 2003
Remaining amortization period			
From Aug. 15, 2003 to Maturity		204.0	months
Assuming 13 Year Extension		360.0	months
Redemption (Call) Price		102%	FIRST CALL October 15, 2003
Amount of Premium		$520,000	
Cost of Funds (Lost Investment Earnings)	5.00%		

P R O P O S E D   R E F U N D I N G

Tax Exempt Pollution Control Bonds

	4.800%	$ 26,000,000	Matures October 15, 2020

Bond Issue Costs			1.71%
Underwriting		0.65%	
Bond Counsel	$	78,000.00	0.30%
Company Counsel	$	70,000.00	0.27%
Underwriters Counu	$	42,000.00	0.16%
Ratings	$	24,000.00	0.09%
Printing	$	6,000.00	0.02%
Trustee Counsel	$	6,000.00	0.02%
Accountants	$	40,000.00	0.15%
AMT	$	-	0.00%
Trustee	$	6,000.00	0.02%
FMB Trustee	$	4,000.00	0.02%
Issuance costs		276,000	1.06%

M I S C E L L A N E O U S

Tax rate	40.363%
Discount rate	2.86%

LYSIS

Present Value SAVINGS
($965,000)
54,886
54,107
53,339
52,582
51,836
51,100
50,375
49,659
48,955
48,260
47,575
46,899
46,234
45,577
44,931
44,293
43,664
43,044
42,433
41,831
41,237
40,652
40,075
39,506
38,945
38,392
37,848
37,310
36,781
36,259
35,744
35,237
34,736
34,243
$523,545

01-Aug-03

PRELIMINARY OFFICIAL STATEMENT DATED AUGUST 16, 1993

WO NEW ISSUES

Subject to the conditions and exceptions set forth under the caption "TAX TREATMENT", Harper, Ferguson & Davis, Louisville, Kentucky ("Bond Counsel"), is of the opinion that, under current law, interest on each series of the Bonds offered hereby (i) will be excludable from the gross income of the recipients thereof for federal income tax purposes, except that no opinion will be expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" or a "related person" as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"), and (ii) will not be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. Such interest may be subject to certain federal taxes imposed on certain corporations, including imposition of the corporate alternative minimum tax on a portion of such interest. Bond Counsel is further of the opinion that interest on each series of the Bonds will be excludable from the gross income of the recipients thereof for Kentucky income tax purposes and that, under current law, principal of each series of the Bonds will be exempt from ad valorem taxes in Kentucky. Issuance of each series of the Bonds is subject to receipt of a favorable tax opinion of Bond Counsel as of the date of delivery of the Bonds. See "TAX TREATMENT" herein.

$35,200,000	***$102,000,000***
County of Jefferson, Kentucky	***County of Jefferson, Kentucky***
Pollution Control Revenue Bonds,	***Pollution Control Revenue Bonds,***
1993 Series A, Due August 15, 2013	***1993 Series B, Due August 15, 2019***
(Louisville Gas and Electric Company Project)	***(Louisville Gas and Electric Company Project)***
Dated: Date of Issuance	***Dated: August 15, 1993***

THE SERIES A BONDS AND THE SERIES B BONDS (COLLECTIVELY, THE "BONDS") WILL BE SPECIAL AND LIMITED OBLIGATIONS OF JEFFERSON COUNTY, KENTUCKY (THE "COUNTY") PAYABLE FROM AMOUNTS RECEIVED UNDER SEPARATE LOAN AGREEMENTS WITH LOUISVILLE GAS AND ELECTRIC COMPANY (THE "COMPANY") AND PLEDGED AS SECURITY FOR SUCH BONDS. THE BONDS WILL NOT CONSTITUTE AN INDEBTEDNESS OR A GENERAL OBLIGATION OR PLEDGE OF THE FAITH AND CREDIT OF THE COMMONWEALTH OF KENTUCKY OR ANY POLITICAL SUBDIVISION THEREOF, INCLUDING THE COUNTY, AND WILL NOT GIVE RISE TO A PECUNIARY LIABILITY OF THE COUNTY OR A CHARGE AGAINST ITS GENERAL CREDIT OR TAXING POWERS.

The Bonds of each series are payable solely from and secured by payments to be received by the County pursuant to separate Loan Agreements with the Company, except as payable as provided herein from accrued interest, if any, Bond proceeds or investment earnings thereon. Principal of, and interest on, the Bonds of each series will be further secured by the delivery to the applicable Trustee of First Mortgage Bonds of

Louisville Gas and Electric Company

The Series A Bonds and the Series B Bonds are separate series and the sale and delivery of one series is not dependent on the sale and delivery of the other series. The Series A Bonds as initially issued will bear interest at Flexible Rates. The initial Flexible Rate to be borne by each Series A Bond will be determined and reset by Goldman, Sachs & Co. as sole Remarketing Agent. The Series B Bonds will initially be issued with a Long Term Rate Period to maturity of August 15, 2019, at   % per annum, payable February 15 and August 15 during such period, commencing February 15, 1994. The interest rate period, interest rate and interest rate mode for each series of Bonds will be subject to change under certain conditions, as described herein.

The Bonds will be issued only as fully registered bonds in denominations of $100,000 and whole multiples thereof while bearing interest at a Daily, Weekly or Semi-Annual Rate; in denominations of $1,000 and whole multiples thereof with a minimum denomination of $100,000 while bearing interest at Flexible Rates; and in denominations of $5,000 and whole multiples thereof while bearing interest at an Annual or Long Term Rate. BankAmerica National Trust Company (New York) is Trustee and Paying Agent for the Series A Bonds. PNC Bank, Kentucky, Inc., Louisville, Kentucky, is Trustee for the Series B Bonds.

The Bonds will be purchased on the demand of the owners thereof on the terms and subject to the conditions described herein. The Bonds will be subject to redemption and mandatory purchase prior to maturity, as described herein, including, but not limited to (i) at the end of each Flexible Rate Period; and (ii) upon conversion of the Bonds from one interest rate mode to a different interest rate mode (except upon conversion between Daily and Weekly Rate Periods) and between Long Term Rate Periods effective for periods of different durations. Tendered Bonds may be remarketed and remain outstanding.

PRICE: 100%

(Plus accrued interest from August 15, 1993 in the case of the Series B Bonds)

The Bonds of each series are offered when, as and if issued by the County and accepted by the Underwriters therefor, subject to prior sale, to withdrawal or modification of the offer without notice and to the approval of legality by Harper, Ferguson & Davis, Louisville, Kentucky, Bond Counsel, the approval of certain other legal matters by Gardner, Carton & Douglas, Chicago, Illinois, and Susan M. Jenkins, Esq., counsel to the Company, and by Winston & Strawn, Chicago, Illinois, counsel to the Underwriters, and certain other conditions. It is expected that delivery of the Bonds will be made on or about August   , 1993, in New York, New York against payment therefor.

Goldman, Sachs & Co.

(Series A Bonds only)

Morgan Stanley & Co. Incorporated

Donaldson, Lufkin & Jenrette Securities Corporation

J.J.B. Hilliard, W.L. Lyons, Inc.

August   , 1993

(Series B Bonds only)

all signatures guaranteed by a bank, trust company or member firm of The New York Stock Exchange, Inc. The Tender Agent may refuse to accept delivery of any Bond for which an instrument of transfer satisfactory to it has not been provided and has no obligation to pay the purchase price of such Bond until a satisfactory instrument is delivered.

If the registered owner of any Bond (or portion thereof) that is subject to purchase pursuant to the Indenture fails to deliver such Bond with an appropriate instrument of transfer to the Tender Agent for purchase on the Purchase Date, and if the Tender Agent is in receipt of the purchase price therefor, such Bond (or portion thereof) nevertheless will be deemed purchased on the Purchase Date thereof. Any owner who so fails to deliver such Bond for purchase on (or before) the Purchase Date will have no further rights thereunder, except the right to receive the purchase price thereof from those moneys deposited with the Tender Agent in the Purchase Fund pursuant to the Indenture upon presentation and surrender of such Bond to the Tender Agent properly endorsed for transfer in blank with all signatures guaranteed.

Redemption Provisions

Optional Redemption.

Optional Redemption During Initial Long Term Rate Period For Series B Bonds.

During the initial Long Term Rate Period for the Series B Bonds, the Series B Bonds will be subject to redemption, in whole or in part, at the option of the County, upon the direction of the Company, on any day, on or after , during the redemption periods and at the redemption prices set forth below, plus interest accrued, if any, to the redemption date:

Redemption Period (both dates inclusive)	Redemption Price as Percentage of Principal Amount
through	%
through	%
and thereafter	%

Optional Redemption During Other Interest Rate Modes and Subsequent Long Term Rate Periods.

(i) Whenever the Interest Rate Mode for the Bonds is the Daily Rate, the Weekly Rate or the Semi-Annual Rate, the Bonds will be subject to redemption, in whole or in part, at the option of the County, upon the direction of the Company, at a redemption price of 100% of the principal amount thereof on any Interest Payment Date.

(ii) Whenever the Interest Rate Mode for a Bond is the Flexible Rate, such Bond will be subject to redemption, in whole or in part, at the option of the County, upon the direction of the Company, at a redemption price of 100% of the principal amount thereof on each Interest Payment Date for that Bond.

(iii) Whenever the Interest Rate Mode for the Bonds is the Annual Rate, the Bonds will be subject to redemption, in whole or in part, at the option of the County, upon the direction of the Company, at a redemption price of 100% of the principal amount thereof on the final Interest Payment Date for each Annual Rate Period.

(iv) Whenever the Interest Rate Mode for the Series A Bonds is the Long Term Rate or in the event the Interest Rate Mode for the Series B Bonds becomes the Long Term Rate following a Conversion or change of the initial Long Term Rate Period for the Series B Bonds, the Bonds will be subject to redemption, in whole or in part, at the option of the County, upon the direction of the Company, (A) on the final Interest Payment

Date for the then current Long Term Rate Period and (B) prior to the end of the then current Long Term Rate Period at any time during the redemption periods and at the redemption prices set forth below, plus interest accrued, if any, to the redemption date:

Original Length of Current Long Term Rate Period (Years)	Commencement of Redemption Period	Redemption Price as Percentage of Principal
More than 15 years	First Interest Payment Date on or after the tenth anniversary of commencement of Long Term Rate Period	102%, declining by ½% on each succeeding anniversary of the first day of the redemption period until reaching 100% and thereafter 100%
More than 13 but not more than 15 years	First Interest Payment Date on or after the eighth anniversary of commencement of Long Term Rate Period	102%, declining by ½% on each succeeding anniversary of the first day of the redemption period until reaching 100% and thereafter 100%
More than 10 but not more than 13 years	First Interest Payment Date on or after the fifth anniversary of commencement of Long Term Rate Period	101½% declining by ½% on each succeeding anniversary of the first day of the redemption period until reaching 100% and thereafter 100%
More than 7, but not more than 10 years	First Interest Payment Date on or after the fifth anniversary of commencement of Long Term Rate Period	101%, declining by ½% on each succeeding anniversary of the first day of the redemption period until reaching 100% and thereafter 100%
More than 3 but not more than 7 years	First Interest Payment Date on or after the third anniversary of commencement of Long Term Rate Period	101%, declining to 100% on the next anniversary of the first day of the redemption period and thereafter 100%
3 years or less	Non-callable	Non-callable

Subject to certain conditions, including provision of an opinion of Bond Counsel that a change in the redemption provisions of the Bonds will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, the redemption periods and redemption prices may be revised effective as of the Conversion Date, the date of a change in the Long Term Rate Period or a Purchase Date on the final Interest Payment Date during a Long Term Rate Period, to reflect Prevailing Market Conditions on such date.

Extraordinary Optional Redemption in Whole. The Bonds may be redeemed by the County in whole at 100% of the principal amount thereof plus accrued interest to the redemption date upon the exercise by the Company of an option under the Loan Agreement to prepay the loan if any of the following events shall have occurred:

(a) if in the judgment of the Company, unreasonable burdens or excessive liabilities shall have been imposed upon the Company after the issuance of the Bonds with respect to the Project or the operation thereof, including without limitation federal, state or other *ad valorem*, property, income or other taxes not imposed on August 15, 1993, other than *ad valorem* taxes presently levied upon privately owned property used for the same general purpose as the Project;

(b) if the Project or a portion thereof or other property of the Company in connection with which the Project is used shall have been damaged or destroyed to such an extent so as, in the judgment of the Company, to render the Project or such other property of the Company unsatisfactory to the Company for its intended use, and such condition shall continue for a period of six months;

(c) there shall have occurred condemnation of all or substantially all of the Project or the taking by eminent domain of such use or control of the Project or other property of the Company in connection with which the Project is used so as, in the judgment of the Company, to render the Project or such other property of the Company unsatisfactory to the Company for its intended use;

(d) in the event changes, which the Company cannot reasonably control, in the economic availability of materials, supplies, labor, equipment or other properties or things necessary for the efficient operation of a Generating Station shall have occurred which, in the judgment of the Company, render the continued operation of such Generating Station or any generating unit at such station uneconomical; or changes in circumstances after the issuance of the Bonds, including but not limited to changes in clean air or other air and water pollution control requirements or solid waste disposal requirements, shall have occurred such that the Company shall determine that use of the Project is no longer required or desirable;

(e) the Loan Agreement shall have become void or unenforceable or impossible of performance by reason of any changes in the Constitution of the Commonwealth of Kentucky or the Constitution of the United States of America or by reason of legislative or administrative action (whether state or federal) or any final decree, judgment or order of any court or administrative body, whether state or federal; or

(f) a final order or decree of any court or administrative body after the issuance of the Bonds shall require the Company to cease a substantial part of its operations at a Generating Station to such extent that the Company will be prevented from carrying on its normal operations at such station for a period of six months.

Extraordinary Optional Redemption in Whole or in Part. The Bonds are also subject to redemption in whole or in part at 100% of the principal amount thereof plus accrued interest to the redemption date at the option of the Company in an amount not to exceed the net proceeds received from insurance or any condemnation award received by the County, the Company or the First Mortgage Trustee in the event of damage, destruction or condemnation of all or a portion of the Project. See "THE LOAN AGREEMENT—Maintenance; Damage, Destruction and Condemnation".

Mandatory Redemption; Event of Taxability. The Bonds are subject to mandatory redemption by the County at 100% of the principal amount thereof plus accrued interest to the redemption date if the Company is required to prepay the amounts due under the Loan Agreement after a final determination by a court of competent jurisdiction or an administrative agency to the effect that as a result of a failure by the Company to perform or observe any covenant or agreement or the inaccuracy of any representations contained in the Loan Agreement or any other agreement or certificate delivered in connection therewith, the interest payable on the Bonds is included for federal income tax purposes in the gross income of any Bondholder (other than any Bondholder who is a "substantial user" of the Project or a "related person" as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended, (the "Code")). Such mandatory redemption shall take place within 180 days after such final determination.

Such redemption is not obligatory unless the Company has participated in or had the opportunity to participate, to a degree the Company reasonably deems sufficient, in the proceeding which resulted in such determination, either directly or through a Bondholder. No determination will be considered final until the conclusion of any appellate review or the expiration of the time for seeking such reviews. Further, no redemption obligation will arise unless such Bondholder permits the Company to participate in such proceedings to the degree the Company reasonably deems sufficient and gives the Company prompt written notice of the commencement of such proceedings. The Bonds will be redeemed in whole, unless the Trustee receives an opinion of Bond Counsel, in accordance with the Indenture, that partial redemption would result in the interest payable on the remaining Bonds outstanding after such redemption not being included in the gross income of any Bondholder, other than a Bondholder who is a "substantial user" of the Project or a "related person" as such terms are used in Section 147(a) of the Code.

If the Internal Revenue Service or a court of competent jurisdiction determines that the interest paid or to be paid on any Bond (except to a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) is or was includible in the gross income of the recipient for federal income tax purposes for reasons other than as a result of a failure by the Company to perform or observe any of its covenants, agreements or representations in the Loan Agreement or any other agreement or certificate delivered in connection therewith, the Bonds are not subject to redemption. In such circumstances, Bondholders would continue to hold their Bonds, receiving principal and interest at the applicable rate as and when due, but would be required to include such interest payments in gross income for federal income tax purposes. Also, if the lien of the Indenture is discharged or defeased prior to the occurrence of a final determination of taxability, Bonds will not be redeemed as described herein.

Mandatory Redemption; Failure to Pay and Discharge Refunded Bonds. The Bonds are also subject to mandatory redemption in whole at 100% of the principal amount thereof plus accrued interest on or prior to the fifteenth day after the date (the "Failed Cross-Over Date") which is the 90th day after the issuance of the Bonds if, on or prior to such 90th day, the Company has not caused the payment and discharge of the Refunded Bonds, in accordance with the indenture or indentures of trust under which the Refunded Bonds were issued.

General Redemption Terms. Notice of redemption will be given by mailing a redemption notice by first class mail to the registered owners of the Bonds to be redeemed not less than 15 days (30 days if the Interest Rate Mode is the Semi-Annual Rate, the Annual Rate or the Long Term Rate), nor more than 60 days prior to the redemption date, except that in the case of a Failed Cross-Over Date, such notice shall be given at least 10 days prior to the redemption date. Any notice mailed as provided in the Indenture shall be conclusively presumed to have been given, irrespective of whether the registered owner receives the notice. Failure to give any such notice by mailing or any defect therein in respect of any Bond will not affect the validity of any proceedings for the redemption of any other Bond. No further interest shall accrue on the principal of any Bond called for redemption after the redemption date if funds sufficient for such redemption have been deposited with the Trustee as of the redemption date.

Discharge of Indenture. Upon certain terms and conditions specified in the Indenture, the Bonds or any portion thereof shall be deemed to be paid, and the assignment of payments made in the Indenture for the security of such Bonds and the security provided by the Pledged First Mortgage Bonds may be discharged, upon the making of provision for payment by irrevocably depositing with the Trustee, cash or Governmental Obligations maturing as to principal and interest at such times as to be sufficient to provide amounts to pay when due the principal of, premium, if any, and interest on such Bonds and all reasonable and necessary fees and expenses of the Trustee and paying agent associated therewith. See "THE INDENTURE—Discharge of Indenture."

THE LOAN AGREEMENT

General

The term of the Loan Agreement relating to the Series A Bonds shall commence as of its date and end on the earliest to occur of August 15, 2013, or the date on which all of the Series A Bonds shall have been fully paid or provision has been made for such payment pursuant to the Indenture. The term of the Loan Agreement relating to the Series B Bonds shall commence as of its date and end on the earliest to occur of August 15, 2019, or the date on which all of the Series B Bonds shall have been fully paid or provision has been made for such payment pursuant to the Indenture. See "THE INDENTURE—Discharge of Indenture."

The Company has agreed to repay the loan pursuant to the Loan Agreement by making timely payments to the Trustee in sufficient amounts to pay the principal of, premium, if any, and interest required to be paid

PRELIMINARY OFFICIAL STATEMENT DATED OCTOBER 18, 1993

NEW ISSUES

ibject to the conditions and exceptions set forth under the caption "TAX TREATMENT", Harper, Ferguson & Davis, Louisville, ucky ("Bond Counsel"), is of the opinion that, under current law, interest on each series of the Bonds offered hereby (i) be excludable from the gross income of the recipients thereof for federal income tax purposes, except that no opinion ...l be expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" or a "related person" as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"), and (ii) will not be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. Such interest may be subject to certain federal taxes imposed on certain corporations, including imposition of the corporate alternative minimum tax on a portion of such interest. Bond Counsel is further of the opinion that interest on each series of the Bonds will be excludable from the gross income of the recipients thereof for Kentucky income tax purposes and that, under current law, principal of each series of the Bonds will be exempt from ad valorem taxes in Kentucky. Issuance of each series of the Bonds is subject to receipt of a favorable tax opinion of Bond Counsel as of the date of delivery of the Bonds. See "TAX TREATMENT" herein.

$26,000,000	$40,000,000
unty of Jefferson, Kentucky	**County of Jefferson, Kentucky**
Pollution Control Revenue Bonds,	Pollution Control Revenue Bonds,
1993 Series C, Due October 15, 2020	1995 Series A, Due April 15, 2023
(Louisville Gas and Electric Company Project)	(Louisville Gas and Electric Company Project)
Dated: October 15, 1993	Dated: April 15, 1995

THE 1993 BONDS AND THE 1995 BONDS (COLLECTIVELY, THE "BONDS") WILL BE SPECIAL AND LIMITED GATIONS OF JEFFERSON COUNTY, KENTUCKY (THE "COUNTY") PAYABLE FROM AMOUNTS RECEIVED UNDER RATE LOAN AGREEMENTS WITH LOUISVILLE GAS AND ELECTRIC COMPANY (THE "COMPANY") AND PLEDGED ECURITY FOR SUCH BONDS. THE BONDS WILL NOT CONSTITUTE AN INDEBTEDNESS OR A GENERAL BLIGATION OR PLEDGE OF THE FAITH AND CREDIT OF THE COMMONWEALTH OF KENTUCKY OR ANY POLITICAL UBDIVISION THEREOF, INCLUDING THE COUNTY, AND WILL NOT GIVE RISE TO A PECUNIARY LIABILITY OF THE ITY OR A CHARGE AGAINST ITS GENERAL CREDIT OR TAXING POWERS.

The Bonds of each series are payable solely from and secured by payments to be received by the County pursuant to parate Loan Agreements with the Company, except as payable as provided herein from accrued interest, if any, Bond proceeds estment earnings thereon. Principal of, and interest on, the Bonds of each series will be further secured by the delivery to ustee of First Mortgage Bonds of

Louisville Gas and Electric Company

he 1993 Bonds and the 1995 Bonds are separate series and the sale and delivery of one series is not dependent on the nd delivery of the other series. The 1993 Bonds will be issued with an interest rate of % per annum, payable April 15 October 15, commencing April 15, 1994. The 1995 Bonds will be issued with an interest rate of % per annum, payable il 15 and October 15, commencing October 15, 1995. The Bonds will be issued only as fully registered bonds, initially in minations of $5,000 and whole multiples thereof. Liberty National Bank and Trust Company of Louisville, Louisville, ucky, is Trustee for the Bonds.

Each series of Bonds will be subject to optional and mandatory redemption prior to maturity, as provided herein. In addition, and after the time a series of Bonds becomes subject to optional redemption, in lieu of redeeming such series of Bonds, the pany may convert the interest rate and interest period for such series of Bonds to a different interest rate and/or interest d. Any such conversion would be subject to the receipt by the registered owners of the Bonds to be converted of the amounts which they would be entitled had their Bonds been redeemed on such date.

PRICE: 100%

(Plus accrued interest from October 15, 1993 in the case of the 1993 Bonds and accrued interest from April 15, 1995 in the case of the 1995 Bonds)

Bonds of each series are offered when, as and if issued by the County and accepted by the Underwriter, subject to prior to withdrawal or modification of the offer without notice and to the approval of legality by Harper, Ferguson & Davis, Louisville, Kentucky, Bond Counsel, the approval of certain other legal matters by Gardner, Carton & Douglas, Chicago, Illinois, and Victor A. Staffieri, General Counsel of the Company, and by Winston & Strawn, Chicago, Illinois, counsel to the Underwriter, and certain other conditions. It is expected that delivery of the 1993 Bonds will be made on or about November , 1993, and delivery of 1995 Bonds will be made on or about April , 1995, in each case, in New York, New York against payment therefor.

Goldman, Sachs & Co.

ber , 1993

the event of a default under the Loan Agreement or default in payment of the principal of, premium, if any, or interest on the Bonds, and upon receipt by the First Mortgage Trustee of a written demand from the Trustee for redemption of the Pledged First Mortgage Bonds, the Pledged First Mortgage Bonds shall begin to bear interest at the same rate borne by the Bonds and the principal of the Pledged First Mortgage Bonds, together with interest deemed accrued thereon from the last date to which interest on the Bonds shall have been paid in full, will be payable in accordance with the Supplemental Indenture. See "THE PLEDGED FIRST MORTGAGE BONDS AND THE FIRST MORTGAGE INDENTURE" and "THE LOAN AGREEMENT—Issuance and Delivery of First Mortgage Bonds."

Payment of the principal of, premium, if any, and interest on the Bonds will be further secured, until the Cross-Over Date, by a pledge of the Escrow Fund. See "THE ESCROW AGREEMENT." Payment of the principal of, premium, if any, and interest on the Bonds will *not* be directly secured by the Project (although the Project is subject to the lien of the First Mortgage Indenture).

Redemption Provisions

Optional Redemption.

The 1993 Bonds will be subject to redemption, in whole or in part, at the option of the County, upon the direction of the Company, on any day, on or after , during the redemption periods and at the redemption prices set forth below, plus interest accrued, if any, to the redemption date:

Redemption Period (both dates inclusive)	**Redemption Price as Percentage of Principal Amount**
through .	%
through .	%
and thereafter	%

The 1995 Bonds will be subject to redemption, in whole or in part, at the option of the County, upon the direction of the Company, on any day, on or after , during the redemption periods and at the redemption prices set forth below, plus interest accrued, if any, to the redemption date:

Redemption Period (both dates inclusive)	**Redemption Price as Percentage of Principal Amount**
through .	%
through .	%
and thereafter	%

The foregoing optional redemption provisions of the Bonds will change upon conversion of the interest rate of the Bonds or the period of time such interest rate is to remain in effect to a different interest rate or different interest period. However, upon any such conversion, registered owners of Bonds will receive the same amount as they would have received if the Bonds had been redeemed in accordance with the foregoing optional redemption provisions. See "Conversion Provisions" below.

Extraordinary Optional Redemption in Whole. The Bonds may be redeemed by the County in whole at 100% of the principal amount thereof plus accrued interest to the redemption date upon exercise by the Company of an option under the Loan Agreement to prepay the loan if any of the following events shall have occurred:

(a) if in the judgment of the Company, unreasonable burdens or excessive liabilities shall have been imposed upon the Company after the issuance of the Bonds with respect to the Project or the operation thereof, including without limitation federal, state or other *ad valorem*, prop income or other taxes not imposed on October 15, 1993, other than *ad valorem* taxes presently levied upon privately owned property used for the same general purpose as the Project;

(b) if the Project or a portion thereof or other property of the Company in connection with which the Project is used shall have been damaged or destroyed to such an extent so as, in the judgment of the Company, to render the Project or such other property of the Company unsatisfactory to the Company for its intended use, and such condition shall continue for a period of six months;

(c) there shall have occurred condemnation of all or substantially all of the Project or the taking by eminent domain of such use or control of the Project or other property of the Company in connection with which the Project is used so as, in the judgment of the Company, to render the Project or such other property of the Company unsatisfactory to the Company for its intended use;

(d) in the event changes, which the Company cannot reasonably control, in the economic availability of materials, supplies, labor, equipment or other properties or things necessary for the efficient operation of a Generating Station shall have occurred which, in the judgment of the Company, render the continued operation of such Generating Station or any generating unit at such station uneconomical; or changes in circumstances after the issuance of the Bonds, including but not limited to changes in clean air or other air and water pollution control requirements or solid waste disposal requirements, shall have occurred such that the Company shall determine that use of the Project is no longer required or desirable;

(e) the Loan Agreement shall have become void or unenforceable or impossible of performance by reason of any changes in the Constitution of the Commonwealth of Kentucky or the Constitution of the United States of America or by reason of legislative or administrative action (whether state or federal) or any final decree, judgment or order of any court or administrative body, whether state or federal; or

(f) a final order or decree of any court or administrative body after the issuance of the Bonds shall require the Company to cease a substantial part of its operations at a Generating Station to such extent that the Company will be prevented from carrying on its normal operations at such station for a period of six months.

Extraordinary Optional Redemption in Whole or in Part. The Bonds also will be subject to redemption in whole or in part at 100% of the principal amount thereof plus accrued interest to the redemption date at the option of the Company in an amount not to exceed the net proceeds received from insurance or any condemnation award received by the County, the Company or the First Mortgage Trustee in the event of damage, destruction or condemnation of all or a portion of the Project. See "THE LOAN AGREEMENT—Maintenance; Damage, Destruction and Condemnation."

Mandatory Redemption; Event of Taxability. The Bonds also will be subject to mandatory redemption by the County at 100% of the principal amount thereof plus accrued interest to the redemption date if the Company is required to prepay the amounts due under the Loan Agreement after a final determination by a court of competent jurisdiction or an administrative agency to the effect that as a result of a failure by the Company to perform or observe any covenant or agreement or the inaccuracy of any representations contained in the Loan Agreement or any other agreement or certificate delivered in connection therewith, the interest payable on the Bonds is included for federal income tax purposes in the gross income of any Bondholder (other than any Bondholder who is a "substantial user" of the Project or a "related person" as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended, (the "Code")). Such mandatory redemption shall take place within 180 days after such final determination.

Such redemption is not obligatory unless the Company has participated in or had the opportunity to participate, to a degree the Company reasonably deems sufficient, in the proceeding which resulted in such determination, either directly or through a Bondholder. No determination will be considered final until the conclusion of any appellate review or the expiration of the time for seeking such reviews. Further, no redemption obligation will arise unless such Bondholder permits the Company to participate in such proceedings to the degree the Company reasonably deems sufficient and gives the Company prompt written notice of the commencement of such proceedings. The Bonds will be redeemed in whole, unless the Trustee receives an opinion of Bond Counsel, in accordance with the Indenture, that partial redemption would result in the interest payable on the remaining Bonds outstanding after such redemption not being included in the gross income of any Bondholder, other than a Bondholder who is a "substantial user" of the Project or a "related person" as such terms are used in Section 147(a) of the Code.

If the Internal Revenue Service or a court of competent jurisdiction determines that the interest paid or to be paid on any Bond (except to a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) is or was includible in the gross income of the recipient for federal income tax purposes for reasons other than as a result of a failure by the Company to perform or observe any of its covenants, agreements or representations in the Loan Agreement or any other agreement or certificate delivered in connection therewith, the Bonds will not be subject to redemption. In such circumstances, Bondholders would continue to hold their Bonds, receiving principal and interest at the applicable rate as and when due, but would be required to include such interest payments in gross income for federal income tax purposes. Also, if the lien of the Indenture is discharged or defeased prior to the occurrence of a final determination of taxability, Bonds will not be redeemed as described above.

Mandatory Redemption; Failure to Pay and Discharge Refunded Bonds. The Bonds also will be subject to mandatory redemption in whole at 100% of the principal amount thereof plus accrued interest on or prior to the fifteenth day after the date (the "Failed Cross-Over Date") which is the 90th day after the issuance of the Bonds if, on or prior to such 90th day, the Company has not caused the payment and discharge of the Refunded Bonds, in accordance with the indenture or indentures of trust under which the Refunded Bonds were issued.

General Redemption Terms. Notice of redemption will be given by mailing a redemption notice by first class mail to the registered owners of the Bonds to be redeemed not less than 30 days, nor more than 60 days, prior to the redemption date, except that in the case of a Failed Cross-Over Date, such notice shall be given at least 10 days prior to the redemption date. Any notice mailed as provided in the Indenture shall be conclusively presumed to have been given, irrespective of whether the registered owner receives the notice. Failure to give any such notice by mailing or any defect therein in respect of any Bond will not affect the validity of any proceedings for the redemption of any other Bond. No further interest shall accrue on the principal of any Bond called for redemption after the redemption date if funds sufficient for such redemption have been deposited with the Trustee as of the redemption date.

Discharge of Indenture. Upon certain terms and conditions specified in the Indenture, the Bonds or any portion thereof shall be deemed to be paid, and the assignment of payments made in the Indenture for the security of such Bonds and the security provided by the Pledged First Mortgage Bonds may be discharged, upon the making of provision for payment by irrevocably depositing with the Trustee, cash or Governmental Obligations maturing as to principal and interest at such times as to be sufficient to provide amounts to pay when due the principal of, premium, if any, and interest on such Bonds and all reasonable and necessary fees and expenses of the Trustee and paying agent associated therewith. See "THE INDENTURE—Discharge of Indenture."

Conversion Provisions

As stated above, the 1993 Bonds will bear interest at the rate of % per annum until maturity and interest on the 1995 Bonds will bear interest at the rate of % per annum until maturity. The Company

LOUISVILLE GAS AND ELECTRIC COMPANY

FINANCIAL EXHIBIT
(807 KAR 5:001 SEC. 6)

March 31, 2003

(1) Amount and kinds of stock authorized.

75,000,000 shares of Common Stock, without par value.
1,720,000 shares of Cumulative Preferred Stock, $25 par value.
6,750,000 shares of Cumulative Preferred Stock, without par value.

(2) Amount and kinds of stock issued and outstanding.

21,294,223 shares of Common Stock, without par value, recorded at $425,170,424.
860,287 shares of Cumulative Preferred Stock, $25 par value, 5% series, $21,507,175.
500,000 shares of Cumulative Preferred Stock, without par value (stated value $100 per share), Auction Rate, $50,000,000.
250,000 shares of Cumulative Preferred Stock, without par value (stated value $100 per share), $5.875 series, $25,000,000.

(3) Terms of preference of preferred stock whether cumulative or participating, or on dividends or assets or otherwise.

The holders of the 5% Cumulative Preferred Stock, $25 par value, are entitled to receive cumulative dividends at an annual rate of 5% of the par value thereof and no more. The holders of the Auction Rate Cumulative Preferred Stock are entitled to receive cumulative dividends at an annual rate of that which results from the auction and no more. The holders of the $5.875 Cumulative Preferred Stock are entitled to receive cumulative dividends at an annual rate of $5.875 per share and no more. Unless dividends on all outstanding shares of each series of the preferred stock, at the respective annual dividend rates and from the dates for accumulation thereof, have been paid for all quarter-yearly periods, no dividends may be paid or declared and no other distribution may be made on the Common Stock, without par value.

In the event of a voluntary liquidation, the holders of the 5% Cumulative Preferred Stock are entitled to $27.25 per share, together with any accumulated but unpaid dividends thereon; provided that, if such voluntary liquidation is approved by the affirmative vote or the written consent of the holders of a majority of a series of preferred stock then outstanding, the amount so payable is $25 per share, together with any accumulated but unpaid dividends thereon. In the event of any involuntary liquidation, the holders of the 5% Cumulative Preferred Stock are entitled to $25 per share, together with any accumulated but unpaid dividends thereon. In the event of a voluntary or involuntary liquidation, the holders of the Auction Rate Cumulative Preferred Stock and the $5.875 Cumulative Preferred Stock are entitled to $100 per share, together with any accumulated but unpaid dividends thereon. After any such liquidation, whether voluntary or involuntary, the holders of the Common Stock, without par value, are entitled to the remaining assets.

(4) Brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name of mortgagee, or trustee, amount of indebtedness authorized to be secured thereby, and the amount of indebtedness actually secured, together with any sinking fund provisions.

The Trust Indenture from Louisville Gas and Electric Company to The Bank of New York, Trustee, dated November 1, 1949, and amended February 15, 1979, secures the First Mortgage Bonds of Louisville Gas and Electric Company. In the opinion of counsel for the Company, the Indenture, as amended and supplemented, constitutes a first mortgage lien, subject only to permissible encumbrances, upon all the property of the Company (with certain specified exceptions) for the equal pro-rata security of all bonds issued or to be issued thereunder, subject to the provisions relating to any sinking fund or similar fund for the benefit of bonds of any particular series. The Indenture contains provisions for subjecting to the lien thereof property acquired by the Company after the data of the Indenture.

The Company has issued First Mortgage Bonds in accordance with the provisions of the Indenture and Supplemental Indentures as follows:

		Principal Amount	
Date of Indenture	Series of Bonds due	Authorized	Outstanding at March, 2003
Aug. 31, 1993	Aug. 15, 2003	42,600,000	$42,600,000
Sept. 17, 1992	Sept. 1, 2017	31,000,000	31,000,000
Sept. 17, 1992	Sept. 1, 2017	60,000,000	60,000,000
Aug. 15, 1993	Aug. 15, 2013	35,200,000	35,200,000
Aug. 15, 1993	Aug. 15, 2019	102,000,000	102,000,000
Oct. 15, 1993	Oct. 15, 2020	26,000,000	26,000,000
Apr. 15, 1995	Apr. 15, 2023	40,000,000	40,000,000
May 1, 2000	May 1, 2027	25,000,000	25,000,000
Aug. 1, 2000	Aug. 1, 2030	83,335,000	83,335,000
Sep. 11, 2001	Sep. 1, 2027	10,104,000	10,104,000
Mar. 6, 2002	Sep. 1, 2026	22,500,000	22,500,000
Mar. 6, 2002	Sep. 1, 2026	27,500,000	27,500,000
Mar. 22, 2002	Nov. 1, 2027	35,000,000	35,000,000
Mar. 22 2002	Nov. 1, 2027	35,000,000	35,000,000
Oct. 23, 2002	Oct. 1, 2032	41,665,000	41,665,000
			$ 616,904,000

(5) Amount of bonds authorized, and amount issued, giving the name of the public utility which issued the same, describing each class separately, and giving date of issue, face value, rate of interest, date of maturity and how secured, together which amount of interest paid thereon during the last fiscal year.

Louisville Gas and Electric Company has issued the following First Mortgage Bonds, which are secured by the Trust Indenture, as amended and supplemented, to The Bank of New York, Trustee:

			Principal Amount		Expense
Date of Issue	Date of Maturity	Rate of Interest	Authorized	Outstanding at March 31, 2003	Year Ended March 31, 2003
Aug. 31, 1993	Aug.15, 2003	6%	42,600,000	42,600,000	2,556,000
The following are Pollution Control Series (a)					
Nov. 01, 1990	Nov. 01, 2020	6.55%	50,000,000	0	1,694,669
Sept. 17, 1992	Sept. 01, 2017	Variable	31,000,000	31,000,000	416,295
Sept. 17, 1992	Sept. 01, 2017	Variable	60,000,000	60,000,000	846,952
Aug. 15, 1993	Aug. 15, 2013	Variable	35,200,000	35,200,000	505,165
Aug. 15, 1993	Aug. 15, 2019	5 5/8%	102,000,000	102,000,000	5,737,500
Oct. 15, 1993	Oct. 15, 2020	5.45%	26,000,000	26,000,000	1,417,000
Apr. 15, 1995	Apr. 15, 2023	5.90%	40,000,000	40,000,000	2,360,000
May 01, 2000	May 01, 2027	Variable	25,000,000	25,000,000	343,820
Aug. 01, 2000	Aug. 01, 2030	Variable	83,335,000	83,335,000	1,176,473
Sep. 11, 2001	Sep. 1, 2027	Variable	10,104,000	10,104,000	144,935
Mar. 6, 2002	Sep. 1, 2026	Variable	22,500,000	22,500,000	309,474
Mar. 6, 2002	Sep. 1, 2026	Variable	27,500,000	27,500,000	377,144
Mar. 22, 2002	Nov. 1, 2027	Variable	35,000,000	35,000,000	501,066
Mar. 22, 2002	Nov. 1, 2027	Variable	35,000,000	35,000,000	500,764
Oct. 23, 2002	Oct. 1, 2032	Variable	41,665,000	41,665,000	241,429

Louisville Gas and Electric Company has also caused to be issued on its behalf the following pollution control bonds which are not secured by First Mortgage Bonds. Theses bonds were discharged in March 2002.

Oct. 1, 1996	Sept. 1, 2026	Variable	22,500,000		0
Oct. 1, 1996	Sept. 1, 2026	Variable	27,500,000		0
Nov. 1, 1997	Nov. 1, 2027	Variable	35,000,000		12,034
Nov. 1, 1997	Nov. 1, 2027	Variable	35,000,000		12,753
Interest rate swap				-	4,373,712
				$616,904,000	$23,527,185

(a) Pollution Control Revenue Bonds (Louisville Gas and Electric Company Projects) issued by Jefferson and Trimble Counties, Kentucky, are secured by the assignment of loan payments by the Company to the County pursuant to loan agreements, and further secured by the delivery from time to time of an equal amount of the Company's First Mortgage Bonds, -Pollution Control Series. First Mortgage Bonds so delivered are summarized in the table above. No principal or interest on these First Mortgage Bonds is payable unless default on the loan agreements occurs. The interest rate stated in the table applies to the Pollution Control Revenue Bonds, not the First Mortgage Bonds. At March 31, 2003, First Mortgage Bonds had been delivered to the trustees as security for all outstanding Pollution Control Revenue Bonds.

(6) Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid thereon during the last fiscal year.

		Intercompany Notes Payable			Interest Expense
Payee	Date of Issue	Date of Maturity	Rate of Interest	Amount	Year Ended March 31, 2003
LG&E Energy Corp	12/00	Various	Various	$248,512,051	$2,507,606

(7) Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of any portion of such indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid thereon during the last fiscal year.

None, other than current and accrued liabilities.

(8) Rate and amount of dividends paid during the five previous fiscal years through March 31, 2003, and the amount of capital stock on which dividends were paid each year.

Dividends on Common Stock, without par value

Month Declared		Payment Date	Amount
March	1997	-	-
June	1997	7/15/97	$ 19,000,000.00
September	1997	10/15/97	20,000,000.00
December	1997	1/15/98	20,000,000.00
			$ 59,000,000.00
March	1998	4/15/98	$ 19,800,000.00
June	1998	7/15/98	21,200,000.00
September	1998	10/15/98	22,000,000.00
December	1998	1/15/99	22,000,000.00
			$ 85,000,000.00
March	1999	4/15/99	$ 22,000,000.00
June	1999	7/15/99	$ 22,000,000.00
September	1999	10/15/97	23,000,000.00
December	1999	1/14/00	23,000,000.00
			$ 90,000,000.00

September	2000	10/15/00	17,000,000.00
December	2000	-	-
			$ 50,000,000.00
March	2001	-	$ -
June	2001	-	-
September	2001	-	-
December	2001	12/18/01	23,000,000.00
			$ 23,000,000.00
March	2002	4/15/02	$ 23,000,000.00
June	2002	-	-
September	2002	10/15/2002	$ 23,000,000.00
December	2002	12/19/2002	$ 23,000,000.00
			$ 69,000,000.00

Number of shares outstanding was 21,294,223 for each period.

Dividends on 5% Cumulative Preferred Stock, $25 par value

For each of the quarters shown for the Common Stock above the Company declared and paid dividends of $.3125 per share on the 860,287 shares of 5% Cumulative Preferred Stock, $25 par value, outstanding for a total of $268,842. On an annual basis the dividend amounted to $1.25 per share, or $1,075,366.

Dividends on $5.875 Cumulative Preferred Stock, without par value

For each of the quarters shown for Common Stock on the previous page the Company declared and paid dividends of $1.4687 per share on the 250,000 shares for a total of $367,187. On an annual basis the dividend amounted to $5.875 per share, or $1,468,750.

Dividends on Auction Rate Cumulative Preferred Stock, without par value

Month Declared		Payment Date	Rate Per Share	Amount
March	1997	4/15/1997	0.98250	$ 491,250
June	1997	7/15/1997	1.05000	$ 525,000
September	1997	10/15/1997	1.01750	$ 508,750
December	1997	1/15/1998	1.03125	$ 515,625
				$ 2,040,625
March	1998	4/15/1998	0.97500	$ 487,500
June	1998	7/15/1998	1.01200	$ 506,000
September	1998	10/15/1998	0.99750	$ 498,750
December	1998	1/15/1999	1.06300	$ 531,500
				$ 2,023,750
				$ 1,957,375
March	2000	4/15/2000	1.05750	$ 528,750
June	2000	7/15/2000	1.36250	$ 681,250
September	2000	10/15/2000	1.45000	$ 725,000
December	2000	1/15/2001	1.46250	$ 731,250
				$ 2,666,250
March	2001	4/15/2001	1.32500	$ 662,500
June	2001	7/15/2001	1.16750	$ 583,750
September	2001	10/15/2001	0.94750	$ 473,750
December	2001	1/14/2002	0.95000	$ 475,000
				$ 2,195,000
March	2002	4/15/2002	0.85875	$ 429,375
June	2002	7/15/2002	0.82500	$ 412,500
September	2002	10/15/2002	0.87750	$ 438,750
December	2002	1/14/2003	0.84250	$ 421,250
				$ 1,701,875

Dividend is based on 500,000 shares for all periods.

(9) Detailed Income Statement and Balance Sheet.

See pages 7 through 9

LOUISVILLE GAS AND ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATING BALANCE SHEET AS OF MARCH 31, 2003

ASSETS AND OTHER DEBITS	CONSOLIDATED
Utility Plant	
Utility Plant at Original Cost	3,688,926,061.44
Less Reserves for Depreciation & Amortization	1,485,615,819.06
Total	2,203,310,242.38
Investments - At Cost	
Ohio Valley Electric Corporation	490,000.00
Investments in LG&E-R	-
Nonutility Property-Less Reserve	111,537.79
Other	-
Total	601,537.79
Current and Accrued Assets	
Cash	5,748,021.44
Special Deposits	29,624.10
Temporary Cash Investments	-
Accounts Receivable-Less Reserve	51,460,816.82
Notes Receivable from Assoc. Companies	-
Notes Receivable from LG&E/LG&E-R	-
Accounts Receivable from Assoc Companies	19,930,538.28
Materials & Supplies-At Average Cost	-
Fuel	33,467,753.83
Plant Materials & Operating Supplies	22,276,207.80
Stores Expense	3,717,920.63
Gas Stored Underground	19,404,434.51
Allowance Inventory	81,336.63
Prepayments	4,814,003.96
Miscellaneous Current & Accrued Assets	869,313.47
Total	161,799,971.47
Deferred Debits and Other	
Unamortized Debt Expense	6,465,541.12
Unamortized Loss on Bonds	18,554,755.49
Accumulated Deferred Income Taxes	126,587,687.15
Deferred Regulatory Assets	102,395,020.55
Other Deferred Debits	81,430,858.71
Total	335,433,863.02
Total Assets and Other Debits	2,701,145,614.66

LIABILITIES AND OTHER CREDITS	CONSOLIDATED
Capitalization	
Common Stock	425,170,424.09
Common Stock Expense	(835,888.64)
Paid-In Capital	40,000,000.00
Unrealized Gain (Loss) on Investment	-
Other Comprehensive Income	(40,532,250.20)
Retained Earnings	435,647,259.54
Total Common Equity	859,449,544.79
Preferred Stock	95,140,346.77
First Mortgage Bonds	574,304,000.00
Pollution Control Bonds (Unsecured)	-
Long-Term Debt Marked to Market	-
Total Capitalization	1,528,893,891.56
Current and Accrued Liabilities	
Long-Term Debt Due in 1 Year	42,600,000.00
Notes Payable to Associated Companies	248,512,051.40
Notes Payable	-
Accounts Payable	81,597,183.65
Accounts Payable to Associated Companies	28,274,572.93
Customer Deposits	10,385,085.52
Taxes Accrued	18,490,461.62
Interest Accrued	3,582,889.86
Dividends Declared	936,029.10
Misc. Current & Accrued Liabilities	4,348,558.55
Total	438,726,832.63
Deferred Credits and Other	
Accumulated Deferred Income Taxes	449,925,805.34
Investment Tax Credit	53,483,810.89
Regulatory Liabilities	46,521,579.00
Customer Advances for Construction	9,780,046.80
Asset Retirement Obligations	9,484,182.50
Other Deferred Credits	20,986,099.16
Misc. Long-Term Liabilities	82,676,264.61
Misc. Long-Term Liab. Due to Assoc. Co.	-
Accum Provision for Post-Retirement Benefits	60,667,102.17
Total	733,524,890.47
Total Liabilities and Other Credits	2,701,145,614.66

LOUISVILLE GAS AND ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATING STATEMENT OF INCOME
MARCH 31, 2003

	CONSOLIDATED
Electric Operating Revenues	193,597,279.07
Gas Operating Revenues	139,824,042.41
Rate Refunds	1,696,178.00
Total Operating Revenues	335,117,499.48
Fuel for Electric Generation	49,477,200.30
Power Purchased	32,401,245.43
Gas Supply Expenses	106,107,177.69
Other Operation Expenses	53,527,824.88
Maintenance	11,893,199.31
Depreciation	25,812,258.99
Amortization Expense	1,361,491.80
Regulatory Credits	(5,464,438.25)
Taxes	-
Federal Income	9,137,872.67
State Income	3,043,543.36
Deferred Federal Income - Net	6,488,062.76
Deferred State Income - Net	1,156,589.68
Federal Income - Estimated	-
State Income - Estimated	-
Property and Other	4,734,564.29
Investment Tax Credit	-
Amortization of Investment Tax Credit	(1,052,633.74)
Gain from Disposition of Allowances	-
Accretion Expense	154,172.50
Total Operating Expenses	298,778,131.67
Net Operating Income	36,339,367.81
Other Income Less Deductions	1,064,024.20
Income Before Interest Charges	37,403,392.01
Interest on Long Term Debt	5,343,510.59
Amortization of Debt Expense - Net	375,591.60
Other Interest Expenses	1,270,658.34
Total Interest Charges	6,989,760.53
Net Inc Before Cumulative Effect of Acctg Chg	30,413,631.48
Cumulative Effect of Accounting Change Net of Tax	3,149,402.00
Net Income	27,264,229.48
Preferred Dividend Requirements	936,028.96
Earnings Available for Common	26,328,200.52

LOUISVILLE GAS AND ELECTRIC COMPANY
ANALYSIS OF RETAINED EARNINGS
MARCH 31, 2003

	YEAR ENDED CURRENT MONTH
	THIS YEAR
Balance at Beginning of Period	413,439,046.23
Add:	
Credits from Income	95,295,064.76
Deduct:	
Preferred Dividends	
$25 Par Value	
5% Series	1,075,365.68
Without Par Value	
Auction Rate	1,572,499.99
$5.875 Series	1,468,750.16
Preferred Dividends Accrued	
$25 Par Value	
5% Series	
Without Par Value	
Auction Rate	
$5.875 Series	
Common Dividends	
Common Stock Without Par Value	69,000,000.00
Balance at End of Period	435,617,495.16

LOUISVILLE GAS AND ELECTRIC COMPANY
(807 KAR 5:001, Section 11, Item 2(b))

Applications to the Commission for authority to issue First Mortgage Bonds included copies of the Trust Indenture and Supplemental Indentures from Louisville Gas and Electric Company to Harris Trust and Savings Bank, Trustee.

The most recent Supplemental Indenture, dated October 1, 2002, was filed in Case No. 2002-230.

Copies of the Supplemental Indentures related to prior First Mortgage bonds were filed in Case Nos. 90-110, 90-271, 92-250, 93-087, 93-223, 2000-051, 2000-052, 2000-275, 2001-205 and 2001-316.

SECRETARY'S CERTIFICATE

I, John R. McCall, do hereby certify that I am the duly qualified and acting Secretary of Louisville Gas and Electric Company (the "Company"), a Kentucky corporation, that as Secretary, I have access to all original records of the Company and that I am authorized to make certified copies of Company records on its behalf. I further hereby certify that the attached resolution was adopted by the Board of Directors of the Company by unanimous written consent in lieu of a meeting, dated July 17, 2003, and that the attached is a full, true and correct copy of said resolutions as they appear on the records of the Company and that the same have not been altered, amended or repealed.

IN WITNESS WHEREOF, I have signed and affixed the seal of the Company this 30th day of July, 2003.

John R. McCall
Executive Vice President, General
Counsel and Secretary

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ACTION OF THE BOARD OF DIRECTORS
OF
LOUISVILLE GAS AND ELECTRIC COMPANY
TAKEN BY WRITTEN CONSENT

July 17, 2003

Refinancing of Pollution Control Revenue Bonds

WHEREAS, the County of Jefferson, Kentucky (the "Issuer") has issued and outstanding: (1) $102,000,000 in principal amount of its Pollution Control Revenue Bonds, 1993 Series B, due August 15, 2019 (Louisville Gas and Electric Company Project) and dated as of August 15, 1993; and (2) $26,000,000 in principal amount of its Pollution Control Revenue Bonds, 1993 Series C, due October 15, 2020 (Louisville Gas and Electric Company Project) and dated as of October 15, 1993 (each series of bonds being herein collectively referred to as the "Existing Pollution Control Bonds"); which provide financing for the acquisition of certain air and water pollution control facilities and solid waste disposal facilities (the "Projects") of the Company in Jefferson County in Kentucky; and

WHEREAS, market conditions may warrant, in the foreseeable future, refinancing of all or a portion of the Existing Pollution Control Bonds, and it is appropriate and in the best interest of the Company that action be taken to authorize such an undertaking; and

WHEREAS, in connection with the refinancing of the Existing Pollution Control Bonds, the Company may secure its payment obligations under one or more loan agreements with the Issuer; and

WHEREAS, such security may be in the form of bond insurance and/or one or more series of the Company's First Mortgage Bonds.

NOW, THEREFORE, BE IT RESOLVED, by the Board of Directors of the Company as follows:

(a) That the Chief Executive Officer, the President, the Chief Financial Officer, any Vice President, Treasurer, or any other officer of the Company be, and each of them hereby is, authorized and directed to cause the preparation of, and to approve, the following documents in connection with the refinancing of all or a portion of the Existing Pollution Control Bonds referred to above: (i) a loan agreement or loan agreements to be entered into between the Company and the Issuer whereby such Issuer will issue one or more series of its Pollution Control Revenue Bonds (collectively, the "Pollution Control Bonds") and loan the proceeds to the Company to be used to pay and discharge all or a part of its Existing Pollution Control Bonds and pursuant to which the Company will be obligated to make loan payments sufficient to pay the principal of, premium, if any, and interest on such Pollution Control Bonds to be issued by such Issuer, and any related expenses, (ii) one or more guaranties from the Company in favor of a trustee or trustees chosen or appointed by such officers of the Company (the "Trustee") for the benefit of the holders of the Pollution Control Bonds guaranteeing repayment of all or any part of the obligations under such Pollution Control Bonds, (iii) such contracts of purchase, underwriting agreements or similar contracts or agreements with the Issuer and with other appropriate parties relating to the issuance of the Pollution Control Bonds, (iv) a preliminary official statement or preliminary official statements and a final official statement or final official statements which will describe the Company, the Issuer, the Projects, the Pollution Control Bonds, the loan agreements, and indentures of trust pursuant to which such Pollution Control Bonds are to be issued, and which will be used by the underwriter or underwriters chosen by such officers of the Company (the "Underwriters") in connection with the sale of such Pollution Control Bonds to the public, (v) a form or forms of escrow agreement, or such other documents as may be deemed appropriate, by and between the Issuer and the respective trustees under the respective indentures pursuant to which the Existing Pollution Control Bonds were issued and pursuant to which certain securities may be held by such trustees in order to provide for the payment and discharge of the Existing Pollution Control Bonds, (vi) such reimbursement agreements, remarketing agreements, auction agreements, broker-dealer agreements, credit agreements, bond insurance documents or agreements or other similar documents or agreements as may be reasonably required, in the event the Pollution Control Bonds, or any of them, are issued as variable rate demand or similar instruments, in the discretion of such officers, (vii) one or more supplemental indentures and/or supplemental trust indentures pursuant to which the Company may issue its Notes or First Mortgage Bonds to secure the transaction, and (viii) such other related documents, forms, certificates or agreements as shall be necessary or appropriate to effectuate such refinancing.

(b) That the officers of the Company be, and each of them hereby is, authorized by and on behalf of the Company, to negotiate and enter into one or more Indentures or similar agreements (collectively, the "Indenture") with a trustee or trustees to be selected by the Chief Executive Officer, the President, the Chief Financial Officer, any Vice President or the Treasurer, as supplemented by one or more supplemental indentures thereto, and to issue from time to time the Notes or First Mortgage Bonds thereunder, each in substantially the form presented to and approved by any such officer with such changes thereto as the officer executing each of such documents deems appropriate, with such officer's execution of the definitive documents to conclusively evidence such officer's approval and the approval of this Board of Directors.

(c) That the Chief Executive Officer, the President, the Chief Financial Officer, any Vice President, Treasurer, or any other officer of the Company be, and each of them hereby is, authorized and empowered (i) to execute and file, or cause to be filed, on behalf of the Company such applications or petitions with any federal, state, or local commission, court, agency or body having jurisdiction as may be required to obtain any approvals, consents, orders or rulings as such officers or counsel for the Company may deem to be necessary or desirable in connection with the Company's participation in such financing and the transactions and documents contemplated thereby, and (ii) to execute and deliver or file such amendments or supplements to said applications or petitions as may be required by law or as may be deemed to be proper or appropriate in their judgment or in the judgment of counsel for the Company in connection with the foregoing.

(d) That the Company shall borrow the sum of not to exceed $128,000,000 from the Issuer in accordance with the terms of the loan agreements, and the proceeds of such borrowings shall be used by the Company to pay and discharge all or a portion of the Existing Pollution Control Bonds and for such other purposes, if any, as may be provided in any of the agreements and documents required to be executed and delivered in connection with the issuance of the Pollution Control Bonds.

(e) That the Chief Executive Officer, the President, the Chief Financial Officer, any Vice President, Treasurer or any other officer of the Company be, and each of them, hereby is authorized to approve offers for the purchase from the County of Jefferson, Kentucky, of not to exceed $128,000,000 principal amount of Pollution Control Bonds. Such purchases may be through negotiation, competitive bidding, or private placement transaction, as determined to be reasonable. The proceeds will be loaned to the Company, at such purchase prices, which shall be not less than the principal amount thereof plus accrued interest from the date of such Pollution Control Bonds to the date of closing, and at such interest rate or rates, as determined to be reasonable.

(f) That the appropriate officers of the Company be, and each of them, hereby is authorized to execute, on behalf of the Company, one or more loan agreements with the County of Jefferson, Kentucky, providing for the loan to the Company of the proceeds of not to exceed $128,000,000 principal amount of Pollution Control Bonds, in accordance with the terms and provisions thereof.

(g) That the appropriate officers of the Company be, and each of them, hereby is authorized to execute, on behalf of the Company, one or more guaranties in favor of the Trustees for the benefit of the holders of the Pollution Control Bonds guaranteeing the payment of all or any part of the obligations under such Pollution Control Bonds.

(h) That the appropriate officers of the Company be, and each of them hereby is, authorized to execute, on behalf of the Company, one or more contracts of purchase, underwriting agreements or similar contracts or agreements with Jefferson County, Kentucky and with other appropriate parties relating to the sale of not to exceed $128,000,000 principal amount of Pollution Control Bonds.

(i) That there is created for issuance under the Trust Indenture, dated

November 1, 1949, as supplemented, from the Company to BNY Midwest Trust Company, Trustee, two new series of bonds of the Company designated "First Mortgage Bonds, Pollution Control Series GG," in a principal amount not to exceed $102,000,000, and "First Mortgage Bonds, Pollution Control Series HH" in a principal amount not to exceed $26,000,000 (collectively, the "Bonds"), the principal amount of and interest on which Bonds shall not be payable except upon the occurrence of an event of default or otherwise as set forth in one or more new Supplemental Indentures pertaining to the Bonds. The terms and provisions thereof shall be substantially as set forth in the form or forms of bond provided in the Supplemental Indentures with such variations (in the event temporary bonds are issued originally) as are contemplated by Section 2.14 of the Trust Indenture.

(j) That for purposes of setting forth the particulars of the Bonds, of specifically subjecting property to the lien of said Trust Indenture as supplemented; of supplementing Article II of said Trust Indenture; and of adding to the covenants set forth in said Trust Indenture new covenants to be performed and observed by it, this Company shall execute and deliver to BNY Midwest Trust Company or its successor, as Trustee, one or more Supplemental Indentures.

(k) That the President, Chief Financial Officer, any Vice President, Treasurer, or any other officer of the Company be and they are hereby authorized, empowered and directed on behalf of this Company to cause the Supplemental Indentures to be filed for record as necessary and to take any other steps to make them binding upon and enforceable against this Company in accordance with their terms.

(l) That the President, any Vice President, Treasurer, or any other officer of the Company be and they are hereby authorized, empowered and directed to execute on behalf of this Company (the signature of Richard Aitken-Davies, as Chief Financial Officer, and the facsimile signature of John R. McCall, as Secretary being hereby approved and adopted) not to exceed $102,000,000 principal amount of First Mortgage Bonds, Pollution Control Series GG, and $26,000,000 principal amount of First Mortgage Bonds, Pollution Control Series HH, of this Company, to cause its corporate seal to be affixed or printed, lithographed or engraved thereon and to cause said Bonds to be authenticated by the manual signature of an authorized officer or agent of BNY Midwest Trust Company or its successor, as Trustee.

(m) That the President, Chief Financial Officer, any Vice President, Treasurer, or any other officer of the Company be and any of them hereby is authorized, empowered and directed to deliver not to exceed $102,000,000 principal amount of First Mortgage Bonds, Pollution Control Series GG, and $26,000,000 principal amount of First Mortgage Bonds, Pollution Control Series HH, on behalf of this Company to the Trustee under an Indenture of Trust from the County of Jefferson, Kentucky, to such Trustee, in accordance with the terms of the contract of purchase, or similar agreement providing for the sale of the Pollution Control Bonds of the Issuer, which Pollution Control Bonds of the Issuer, are described herein.

(n) That BNY Midwest Trust Company or its successor, as Trustee, be and it is hereby authorized, empowered and directed, upon compliance by the Company with the applicable provisions of said Trust Indenture dated November 1, 1949, as supplemented and as it is to be supplemented, to authenticate and deliver not to exceed $102,000,000 principal amount of First Mortgage Bonds, Pollution Control Series GG, and $26,000,000 principal amount of First Mortgage Bonds, Pollution Control Series HH.

(o) That the President, Chief Financial Officer, any Vice President, Treasurer or any other officer of the Company be and any of them is hereby authorized, empowered and directed to execute any and all instruments, pay any and all taxes, and do any and all acts and things that may be necessary or required by said Trust Indenture dated November 1, 1949, as supplemented and as it is to be supplemented, or that may in their judgment be advisable to effectuate the issuance, authentication, delivery and sale of not to exceed $128,000,000 principal amount of the Bonds according to the tenor and purport of these resolutions, and without limitation of the foregoing that the officers of this Company be and they are hereby authorized, empowered and directed to make an application or applications to the Trustee as provided in Article IV of said Trust Indenture dated November 1, 1949, for authentication and delivery by the Trustee of the Bonds, in the aggregate principal amount of not to exceed $128,000,000 under the provisions of Articles IV, V and/or VI of said Trust Indenture dated November 1, 1949.

(p) That the President, Chief Financial Officer, any Vice President, or any other officer of the Company be and they are hereby authorized, empowered and directed to cause this Company's corporate name and seal to be affixed to said Supplemental Indentures and to sign, attest, acknowledge and deliver said Supplemental Indentures for and in behalf of this Company.

(q) That the officers of the Company be, and each of them hereby is, authorized by and on behalf of the Company, to negotiate and enter into one or more bond insurance or similar agreements with a bond insurer to be selected by the Chief Executive Officer, the President, Chief Financial Officer, any Vice President or the Treasurer, each in substantially the form presented to and approved by any such officer with such changes thereto as the officer executing each of such documents shall deem necessary or advisable, the execution of such documents thereby to conclusively evidence such officer's approval and the approval of this Board of Directors.

(r) That in the event all or a portion of the Pollution Control Bonds bear a variable rate of interest, the appropriate officers of the Company be, and each of them, hereby is authorized to execute on behalf of the Company one or more remarketing agreements, auction agreements, reimbursement agreements or similar agreements with appropriate parties providing for the remarketing of such Pollution Control Bonds, a credit agreement or credit agreements or similar agreements and any promissory notes to be issued pursuant to such agreements for the purpose of providing a source of funds upon tender of such Pollution Control Bonds, and any other agreements in order to consummate the transactions contemplated by the loan agreement or loan agreements.

(s) That the appropriate officers of the Company be, and each of them, hereby is authorized to execute on behalf of the Company: (i) one or more interest rate swap, collar, or cap agreements or similar agreements with one or more underwriters, banks or other financial institutions providing for the hedging of the interest rate on the Pollution Control Bonds and (ii) any other agreement, document or instrument that may be necessary or appropriate in connection with any such transaction.

(t) That the Chief Executive Officer, the President, any Vice President, or any other officer of the Company be, and each one of them is, authorized, empowered and directed to take any action and to execute and deliver any document, certificate or other instrument, including one or more escrow agreements, that may be necessary or appropriate: (i) to call for redemption the Existing Pollution Control Bonds on such date as said officer or officers may deem appropriate, or (ii) to otherwise effect the payment and discharge of the Existing Pollution Control Bonds.

(u) That the officers of the Company be, and each of them hereby is, authorized in the name and on behalf of the Company and under its corporate seal or otherwise, to take or cause to be taken all such further actions and to execute and deliver or cause to be executed and delivered all such further documents, bond insurance documents or agreements, certificates and agreements (including without limitation, instruments authorizing or consenting to amendment, modifications or waivers to any of the agreements or disclosure documents executed in connection with the issuance, execution and delivery of the Pollution Control Bonds, the issuance, execution and delivery of the Notes or Bonds, the execution and delivery of the bond insurance documents or agreements, and the execution and delivery of the Indenture) as such persons may deem necessary, advisable or appropriate in connection with the transactions contemplated thereby and hereby, and to incur all such fees and expenses as shall be necessary, advisable or appropriate in their judgment in order to carry into effect the purpose and intent of any and all of the foregoing resolutions.

(v) That the Chief Executive Officer, the President, Chief Financial Officer, any Vice President, Treasurer or any other officer of the Company be and they are hereby authorized and empowered to take all steps or actions, and to execute and deliver any other documents, certificates or other instruments, deemed necessary, proper or appropriate in their judgment or in the judgment of counsel for the Company in connection with the financing referred to above and to carry out the purposes of the foregoing resolutions.

(w) That Daniel K. Arbough is hereby appointed as "Company Representative" and S. Bradford Rives and Richard Aitken-Davies are hereby appointed as "Alternate Company Representatives," respectively, under the provisions of the pollution control indentures and the loan agreements. The President and any Vice President, the Chief Financial Officer or the Treasurer of the Company are authorized to appoint from time to time other persons (who may be employees of the Company) to act as "Company Representative" or "Alternate Company Representative" under the pollution control indentures and the loan agreements.

(x) That any acts of the officers of this Company, which acts would have been authorized by the foregoing resolutions except that such acts were taken prior to the adoption of such resolutions, are hereby severally ratified, confirmed, approved and adopted as acts in the name of and on behalf of this Company.

(y) That the Board of Directors does hereby adopt, as if fully set out herein, the form of any resolutions with respect to the Pollution Control Bonds as may be required by the Underwriters, BNY Midwest Trust Company, as Trustee, and any other entities requiring such resolutions to effect the intent of these resolutions.

(aa) That each of the Chief Executive Officer, President, Chief Financial Officer, any Vice President, the Chief Financial Officer, the Treasurer, the Secretary or any Assistant Secretary of the Company be, and hereby is, authorized and directed to take any and all further action to see that the intent of the above resolutions are carried forth.

EXHIBIT 6

FORM OF PROPOSED ORDER
COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ORDER AUTHORIZING THE ISSUANCE OF SECURITIES AND THE ASSUMPTION OF OBLIGATIONS	)))))	Case No. 2003-________

ORDER

On ________________, 2003, Louisville Gas and Electric Company ("LG&E") filed an Application to Issue its First Mortgage Bonds in an aggregate principal amount not to exceed $128,000,000 and to assume certain obligations in connection therewith, represented by Loan Agreement(s) with Louisville Jefferson County Metro Government ("Metro Government") in connection with the simultaneous issuance by the Metro Government of the Metro Government Refunding Bonds, the proceeds of which will be loaned to LG&E. LG&E will use the proceeds of such Metro Government Refunding Bonds to provide refunding of the $102,000,000 principal amount of County of Jefferson, Kentucky Pollution Control Revenue Bonds (Louisville Gas and Electric Company Project), 1993 Series B and the $26,000,000 principal amount of County of Jefferson, Kentucky Pollution Control Revenue Bonds (Louisville Gas and Electric Company Project), 1993 Series C (collectively the "Existing Bonds"). The proposed First Mortgage Bonds of LG&E will be used to secure and collateralize the Metro Government Refunding Bonds. LG&E has also requested authority to execute and deliver, as required, and to perform its obligations under, loan agreements with the Metro Government, and any remarketing agreements and the various credit enhancing facilities, auction and other agreements, and notes as are set forth in the Application and to perform the transactions contemplated by those agreements.

The Commission, having considered the evidence of record and being otherwise sufficiently advised, finds that the issuance of the proposed First Mortgage Bonds and the Metro Government Refunding Bonds and assumption of obligations in connection therewith as set out in LG&E's Application will result in lower overall debt costs for LG&E and consequently the public, and is for lawful objects and within the corporate purposes of LG&E's utility operations, is necessary and appropriate for and consistent with the proper performance of its service to the public, will not impair its ability to perform that service, is reasonably necessary and appropriate for such purposes, and should therefore be approved.

IT IS THEREFORE ORDERED:

1. LG&E is authorized to issue and deliver the new First Mortgage Bonds in one or more series in an aggregate principal amount not to exceed $128,000,000 in the manner set forth in this Application.

2. LG&E is authorized to execute, deliver and perform the obligations of LG&E under, inter alia, the loan agreement(s) with the Metro Government, and under any remarketing agreements, hedging agreements, auction agreements, bond insurance agreements, credit agreements and facilities, and such other agreements and documents as set out in its Application, and to perform the transactions contemplated by all such agreements.

3. The proceeds form the transactions authorized herein shall be used only for the lawful purposes set out in the Application.

4. LG&E shall agree only to such terms and prices that are consistent with the parameters set out in its Application.

5. LG&E shall, within thirty-days (30) of the date of issuance, file with this Commission a statement setting forth the date or dates of issuance, the price paid, the interest rate or rates, and all fees and expenses, including underwriting discounts or commissions or other compensations, involved in the issuance and distribution of the Metro Government Refunding Bonds and the refunding and discharge of the Existing Bonds.

Nothing contained herein shall be construed as a finding of value for any purpose or as a warranty on the part of the Commonwealth of Kentucky or any agency thereof as to the securities authorized herein.

Done at Frankfort, Kentucky this __________ day of ____________________, 2003.

By the Commission

ATTEST:

____
Executive Director

280586.5

Arbough Rebuttal Exhibit 2

Consolidated Fixed Floating Debt Mix
as of December 31, 2009

	LG&E	% of Total	KU	% of Total
Fixed	156,000,000	13%	26,802,000	2%
Floating	418,304,000	34%	323,977,405	19%
Money Pool	170,400,000	14%	44,974,954	3%
Fixed Rate Loans from E.ON	485,000,000	39%	1,331,000,000	77%
Floating Rate Loans from E.ON	-	0%	-	0%
Redeemable Preferred Stock	-	0%	-	0%
Floating Rate Leases	-	0%	-	0%
Total	1,229,704,000		1,726,754,359	
Swapped	179,335,000		-	
New Swap/Fixed Rate Debt	-		-	
New Debt				
Fixed				
Floating				
Adjusted				
Fixed	820,335,000	67%	1,357,802,000	79%
Floating	409,369,000	33%	368,952,359	21%
Total	1,229,704,000		1,726,754,359	
Excluding Debt Incurred to Hold Tax-exempt Bonds				
Fixed	820,335,000	77%	1,357,802,000	79%
Floating	246,162,620	23%	368,952,359	21%
Total	1,066,497,620		1,726,754,359	
impact of 1% change after swaps	4,254,976		3,689,524	
effect of swaps	(1,793,350)		-	
impact of 1% change before swaps	2,461,626		3,689,524	

Arbough Rebuttal Exhibit 3

LG&E - WACHOVIA SWAP 12/12/03
LG&E Pays 3.648% and receives 68% of 1 mo LIBOR

Notional Amount	Rate	Day Count	From Date	To Date		Floating Rate Leg	Fixed Rate Leg	Net Savings from Swap Termination
$ 32,000,000	1.29200%	360	12/17/2008	1/2/2009	16	18,375.11	48,640.00	30,264.89
$ 32,000,000	0.30430%	360	1/2/2009	2/2/2009	31	8,385.16	97,280.00	88,894.84
$ 32,000,000	0.28050%	360	2/2/2009	3/2/2009	28	6,981.33	97,280.00	90,298.67
$ 32,000,000	0.33788%	360	3/2/2009	4/1/2009	30	9,010.08	94,037.33	85,027.25
$ 32,000,000	0.34595%	360	4/1/2009	5/1/2009	30	9,225.33	97,280.00	88,054.67
$ 32,000,000	0.28433%	360	5/1/2009	6/1/2009	31	7,834.87	97,280.00	89,445.13
$ 32,000,000	0.21760%	360	6/1/2009	7/1/2009	30	5,802.67	97,280.00	91,477.33
$ 32,000,000	0.20995%	360	7/1/2009	8/3/2009	33	6,158.53	103,765.33	97,606.80
$ 32,000,000	0.19083%	360	8/3/2009	9/1/2009	29	4,919.12	90,794.67	85,875.55
$ 32,000,000	0.17765%	360	9/1/2009	10/1/2009	30	4,737.33	97,280.00	92,542.67
$ 32,000,000	0.16745%	360	10/1/2009	11/2/2009	32	4,763.02	100,522.67	95,759.65
$ 32,000,000	0.16558%	360	11/2/2009	12/1/2009	29	4,268.28	94,037.33	89,769.05
$ 32,000,000	0.16001%	360	12/1/2009	1/4/2010	34	4,835.88	107,008.00	102,172.12
$ 32,000,000	0.15704%	360	1/4/2010	2/1/2010	28	3,908.53	87,552.00	83,643.47
$ 32,000,000	0.15555%	360	2/1/2010	3/1/2010	28	3,871.47	97,280.00	93,408.53
$ 32,000,000	0.15555%	360	3/1/2010	4/1/2010	31	4,286.27	97,280.00	92,993.73
$ 32,000,000	0.16907%	360	4/1/2010	5/4/2010	33	4,959.33	107,008.00	102,048.67
Net savings due to termination of swap								1,499,283.01

Arbough Rebuttal Exhibit 4

STANDARD
&POOR'S

Global Credit Portal
RatingsDirect®

May 27, 2009

Criteria | Corporates | General:

Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

Primary Credit Analysts:
Solomon B Samson, New York (1) 212-438-7653; sol_samson@standardandpoors.com
Emmanuel Dubois-Pelerin, Paris (33) 1-4420-6673, emmanuel_dubois-pelerin@standardandpoors.com

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Criteria | Corporates | General:

Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

(Editor's Note: In the previous version of this article published on May 26, certain of the rating outcomes in the table 1 matrix were missated. A corrected version follows.)

Standard & Poor's Ratings Services is refining its methodology for corporate ratings related to its business risk/financial risk matrix, which we published as part of 2008 Corporate Ratings Criteria on April 15, 2008, on RatingsDirect at www.ratingsdirect.com and Standard & Poor's Web site at www.standardandpoors.com.

This article amends and supersedes the criteria as published in Corporate Ratings Criteria, page 21, and the articles listed in the "Related Articles" section at the end of this report.

This article is part of a broad series of measures announced last year to enhance our governance, analytics, dissemination of information, and investor education initiatives. These initiatives are aimed at augmenting our independence, strengthening the rating process, and increasing our transparency to better serve the global markets.

We introduced the business risk/financial risk matrix four years ago. The relationships depicted in the matrix represent an essential element of our corporate analytical methodology.

We are now expanding the matrix, by adding one category to both business and financial risks (see table 1). As a result, the matrix allows for greater differentiation regarding companies rated lower than investment grade (i.e., 'BB' and below).

Table 1

Business And Financial Risk Profile Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	CCC+

These rating outcomes are shown for guidance purposes only. Actual rating should be within one notch of indicated rating outcomes.

The rating outcomes refer to issuer credit ratings. The ratings indicated in each cell of the matrix are the midpoints of a range of likely rating possibilities. This range would ordinarily span one notch above and below the indicated rating.

Business Risk/Financial Risk Framework

Our corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several categories so that all salient issues are considered. The first categories involve fundamental business analysis; the financial analysis categories follow.

Our ratings analysis starts with the assessment of the business and competitive profile of the company. Two companies with identical financial metrics can be rated very differently, to the extent that their business challenges and prospects differ. The categories underlying our business and financial risk assessments are:

Business risk

- Country risk
- Industry risk
- Competitive position
- Profitability/Peer group comparisons

Financial risk

- Accounting
- Financial governance and policies/risk tolerance
- Cash flow adequacy
- Capital structure/asset protection
- Liquidity/short-term factors

We do not have any predetermined weights for these categories. The significance of specific factors varies from situation to situation.

Updated Matrix

We developed the matrix to make explicit the rating outcomes that are typical for various business risk/financial risk combinations. It illustrates the relationship of business and financial risk profiles to the issuer credit rating.

We tend to weight business risk slightly more than financial risk when differentiating among investment-grade ratings. Conversely, we place slightly more weight on financial risk for speculative-grade issuers (see table 1, again). There also is a subtle compounding effect when both business risk and financial risk are aligned at extremes (i.e., excellent/minimal and vulnerable/highly leveraged.)

The new, more granular version of the matrix represents a refinement--not any change in rating criteria or standards--and, consequently, holds no implications for any changes to existing ratings. However, the expanded matrix should enhance the transparency of the analytical process.

Financial Benchmarks

Table 2

Financial Risk Indicative Ratios (Corporates)

	FFO/Debt (%)	Debt/EBITDA (x)	Debt/Capital (%)
Minimal	greater than 60	less than 1.5	less than 25
Modest	45-60	1.5-2	25-35
Intermediate	30-45	2-3	35-45
Significant	20-30	3-4	45-50
Aggressive	12-20	4-5	50-60
Highly Leveraged	less than 12	greater than 5	greater than 60

How To Use The Matrix--And Its Limitations

The rating matrix indicative outcomes are what we typically observe--but are not meant to be precise indications or guarantees of future rating opinions. Positive and negative nuances in our analysis may lead to a notch higher or lower than the outcomes indicated in the various cells of the matrix.

In certain situations there may be specific, overarching risks that are outside the standard framework, e.g., a liquidity crisis, major litigation, or large acquisition. This often is the case regarding credits at the lowest end of the credit spectrum--i.e., the 'CCC' category and lower. These ratings, by definition, reflect some impending crisis or acute vulnerability, and the balanced approach that underlies the matrix framework just does not lend itself to such situations.

Similarly, some matrix cells are blank because the underlying combinations are highly unusual--and presumably would involve complicated factors and analysis.

The following hypothetical example illustrates how the tables can be used to better understand our rating process (see tables 1 and 2).

We believe that Company ABC has a satisfactory business risk profile, typical of a low investment-grade industrial issuer. If we believed its financial risk were intermediate, the expected rating outcome should be within one notch of 'BBB'. ABC's ratios of cash flow to debt (35%) and debt leverage (total debt to EBITDA of 2.5x) are indeed characteristic of intermediate financial risk.

It might be possible for Company ABC to be upgraded to the 'A' category by, for example, reducing its debt burden to the point that financial risk is viewed as minimal. Funds from operations (FFO) to debt of more than 60% and debt to EBITDA of only 1.5x would, in most cases, indicate minimal.

Conversely, ABC may choose to become more financially aggressive--perhaps it decides to reward shareholders by borrowing to repurchase its stock. It is possible that the company may fall into the 'BB' category if we view its financial risk as significant. FFO to debt of 20% and debt to EBITDA 4x would, in our view, typify the significant financial risk category.

Still, it is essential to realize that the financial benchmarks are guidelines, neither gospel nor guarantees. They can vary in nonstandard cases: For example, if a company's financial measures exhibit very little volatility, benchmarks may be somewhat more relaxed.

Moreover, our assessment of financial risk is not as simplistic as looking at a few ratios. It encompasses:

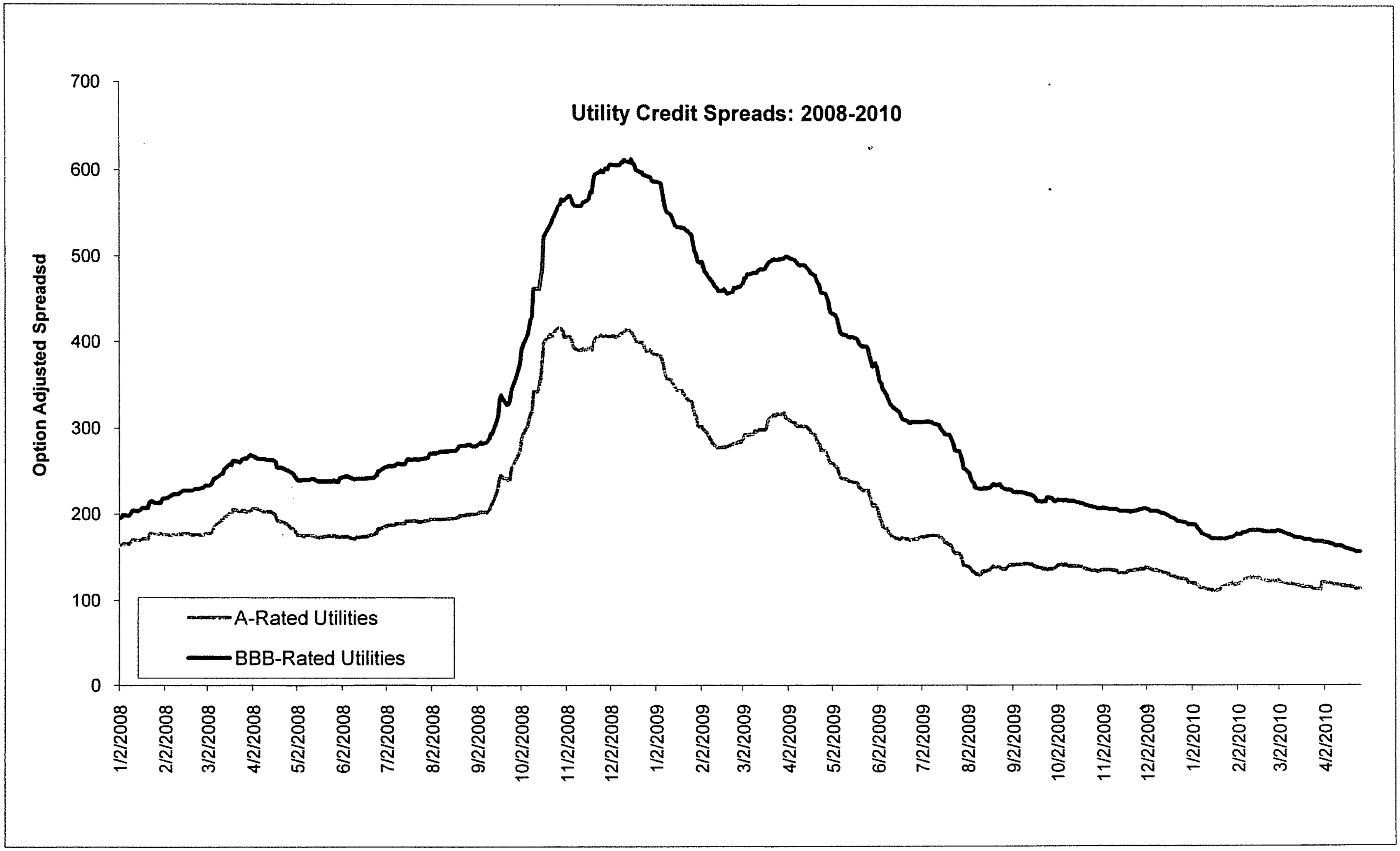
- a view of accounting and disclosure practices;
- a view of corporate governance, financial policies, and risk tolerance;
- the degree of capital intensity, flexibility regarding capital expenditures and other cash needs, including acquisitions and shareholder distributions; and
- various aspects of liquidity--including the risk of refinancing near-term maturities.

The matrix addresses a company's standalone credit profile, and does not take account of external influences, which would pertain in the case of government-related entities or subsidiaries that in our view may benefit or suffer from affiliation with a stronger or weaker group. The matrix refers only to local-currency ratings, rather than foreign-currency ratings, which incorporate additional transfer and convertibility risks. Finally, the matrix does not apply to project finance or corporate securitizations.

Related Articles

Industrials' Business Risk/Financial Risk Matrix--A Fundamental Perspective On Corporate Ratings, published April 7, 2005, on RatingsDirect.

Arbough Rebuttal Exhibit 5


Utility Credit Spreads: 2008-2010
Option Adjusted Spreadsd
700
600
500
400
300
200
100
0
A-Rated Utilities
BBB-Rated Utilities
1/2/2008
2/2/2008
3/2/2008
4/2/2008
5/2/2008
6/2/2008
7/2/2008
8/2/2008
9/2/2008
10/2/2008
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2/2/2010
3/2/2010
4/2/2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS & ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	)))))	**CASE NO. 2009-00549**

REBUTTAL TESTIMONY

OF

WILLIAM E. AVERA

on behalf of

LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: May 27, 2010

REBUTTAL TESTIMONY OF WILLIAM E. AVERA

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. DID YOU PREVIOUSLY SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I did.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS CASE?

A. My purpose is to respond to the testimony of Dr. J. Randall Woolridge, submitted on behalf of the Kentucky Office of Attorney General ("OAG"), and Mr. Richard A. Baudino, on behalf of the Kentucky Industrial Utility Consumers ("KIUC"), concerning the fair rate of return on equity ("ROE") that Louisville Gas and Electric Company ("LGE" or "the Company") should be authorized to earn on its investment in providing electric and gas utility service. In addition, I also respond to the capital structure recommendations of Dr. Woolridge and I will also rebut the financial arguments of Dr. Woolridge and Ms. Nancy Brockway, on behalf of AARP, concerning the impact of LGE's proposed rate design on a fair ROE. Finally, my rebuttal testimony also responds to the ROE recommended by Thomas J. Prisco, on behalf of the United States Department of Defense.

Q. PLEASE SUMMARIZE THE PRINCIPAL CONCLUSIONS OF YOUR REBUTTAL TESTIMONY.

A. Dr. Woolridge's and Mr. Baudino's recommendations are flawed and should be rejected. Correcting and supplementing their analyses resulted in the following cost of equity estimates:

TABLE WEA-8
COST OF EQUITY – BAUDINO AND WOOLRIDGE PROXY GROUPS

Revised DCF Analysis	
Woolridge - Electric	11.0%
Woolridge - Gas	10.0%
Baudino	10.6%
DCF Price Growth	
Woolridge - Electric	11.4%
Woolridge - Gas	10.3%
Baudino	10.5%
Expected Earnings Approach	
Woolridge - Electric	10.9%
Woolridge - Gas	11.9%
Baudino	11.2%
Allowed ROE	
Woolridge - Electric	10.7%
Woolridge - Gas	10.5%
Baudino	10.6%
Average - All Analyses	**10.8%**

With respect to their analyses I conclude that:

- *Because of flaws in the screening criteria and data used Mr. Baudino and Dr. Woolridge,, their proxy groups of electric utilities should be rejected;*
- *Utilities have significantly altered their dividend policies in recent years and Mr. Baudino's and Dr. Woolridge's reliance on dividend growth rates to apply the discounted cash flow ("DCF") model imparts a downward bias to their results;*
- *Because Mr. Baudino Dr. Woolridge incorporated numerous illogical growth rate estimates, their DCF cost of equity estimates are biased downward;*
- *Because the calculations underlying Mr. Baudino's and Dr. Woolridge's internal growth rates are flawed and incomplete, this growth measure should be ignored;*
- *Growth in stock price is consistent with the assumptions underlying the DCF method and investors' expectations.*

My rebuttal testimony also demonstrates that:

- *Contrary to Dr. Woolridge's and Mr. Baudino's unsupported allegations, the expected earnings approach is entirely consistent with the regulatory and economic principles advanced in their testimony;*
- *Applying the expected earnings approach to the proxy groups of Mr. Baudino and Dr. Woolridge demonstrates that their recommendations are woefully inadequate to compensate investors in LGE;*
- *While allowed ROEs demonstrate that Mr. Baudino's and Dr. Woolridge's recommendations are too low to be credible, Mr. Prisco failed to conduct any independent analyses or consider the relative risks of LGE;*
- *Dr. Woolridge and Mr. Baudino ignored the results of their applications of the Capital Asset Pricing Model ("CAPM") and so should the Kentucky Public Service Commission ("KPSC");*
- *The failure of Mr. Baudino and Dr. Woolridge to consider the impact of flotation costs contradicts the findings of the financial literature and the economic requirements underlying a fair rate of return on equity;*
- *Mr. Prisco performed no independent analyses of a fair ROE for LGE and his recommendation fails to consider current capital market data or the specific risks and requirements of LGE.*

In addition, I show that there is no basis for the conclusions of Dr. Woolridge or Ms. Brockway that approval of LGE's proposed rate design would support a reduction to the allowed ROE:

- *Investors would view the proposed rate design as supportive of LGE's financial integrity, but there is no evidence that these provisions will result in a measurable change in the Company's investment risk or ROE relative to the proxy companies;*
- *Utilities across the U.S. are increasingly availing themselves of similar adjustments and because the utilities in the proxy groups referenced by Dr. Woolridge and me operate under a variety of rate design and adjustment mechanisms, the impact of utilities' ability to mitigate the risk of declining revenues and cash flows is already reflected;*
- *Dr. Woolridge's reference to other regulatory decisions is incomplete and misleading and the magnitude of his suggested adjustment is completely inconsistent with capital market evidence.*

With respect to Dr. Woolridge's recommended capital structure, my rebuttal testimony demonstrates that there is no basis for the hypothetical equity ratio he selects. Finally, my rebuttal testimony demonstrates that Dr. Woolridge's and Mr. Baudino's criticisms of my alternative applications and conclusions are misguided and should be ignored.

II. DCF RESULTS ARE UNDERSTATED

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 or by reference to the median.

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

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 (pp.

31-33), 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 dividend growth rates, for example. If past trends in DPS 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 as utilities significantly altered their dividend policies in response to more accentuated business risks in the industry. As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties

As I explained in my direct testimony, specific trends in dividend policies for utilities and evidence from the investment community fully support my conclusion that earnings growth projections are likely to provide a superior guide to investors' expectations. While past conditions for utilities serve to depress DPS growth measures, they are not representative of long-term expectations for the utility industry.

Q. DID DR. WOOLRIDGE AND MR. BAUDINO RECOGNIZE THE PITFALLS ASSOCIATED WITH HISTORICAL GROWTH RATES?

A. Yes. Dr. Woolridge noted that:

> [T]o best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.[1]

But as he acknowledged, historical growth rates can differ significantly from the forward-looking growth rate required by the DCF model:

> [O]ne must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles).[2]

Similarly, Mr. Baudino noted (p. 21) that the analysis of investors' cost of equity "is a forward-looking process," and that historical growth rates "may not accurately represent investors' expectations." Mr. Baudino concluded that analysts' forecasts "provide better proxies for the expected growth components in the DCF model than historical growth rates." Moreover, to the extent historical trends for utilities are meaningful, they are already captured in projected growth rates, including those published by Value Line, First Call, Zacks, and Thomson Reuters, since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends.

Q. IS THE DOWNWARD BIAS IN DR. WOOLRIDGE'S HISTORICAL GROWTH MEASURES SELF EVIDENT?

A. Yes, it is. As shown on page 3 of Exhibit JRW-10, approximately one-third of the individual historical growth rates reported by Dr. Woolridge for the companies in his electric proxy group were *zero* or *negative*, with over one-half being 1.5 percent or

[1] Woolridge Direct at 30.
[2] Woolridge Direct at 29-30.

less. Combining a growth rate of 1.5 percent with Dr. Woolridge's dividend yield of 4.9 percent implies a DCF cost of equity of approximately 6.4 percent.[3] This implied cost of equity barely exceeds the yield currently available to investors from triple-B public utility bonds, which averaged 6.2 percent in April 2010.[4] Clearly, the risks associated with an investment in public utility common stocks exceed those of long-term bonds. As Mr. Baudino noted (p. 22), negative growth rates should be excluded because they "are inconsistent with the assumption of constant positive growth in the DCF formula." 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 MAKE ANY EFFORT TO TEST THE REASONABLENESS OF THE INDIVIDUAL GROWTH ESTIMATES HE RELIED ON TO APPLY THE CONSTANT GROWTH DCF MODEL?

A. No. Despite recognizing that caution is warranted in using historical growth rates, 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, as demonstrated above, many of the cost of equity estimates implied by Dr. Woolridge's DCF application make no economic sense.

For example, consider the 5-year historical BVPS growth rates included in Dr. Woolridge's evaluation. As shown on page 3 of Exhibit JRW-10, the individual values for the firms in his electric proxy group ranged from –2.0 percent to 14.5 percent. Combining these growth rates referenced by Dr. Woolridge with his average dividend yield suggests a DCF cost of equity range of 2.9 percent to 19.4

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[3] Adjusting Dr. Woolridge's average dividend yield of 4.9 percent (Exhibit JRW-10, p. 1) for one-half year's growth at 1.5 percent implies a dividend yield of approximately 4.5 percent.

[4] Moody's Investors Service, www.credittrends.com.

percent. Clearly, DCF estimates that imply a cost of equity below the yield on risk-free Treasury bonds or approaching 20 percent violate economic logic and hardly represent an informed evaluation of investors' expectations.

Q. DOES REFERENCE TO THE MEDIAN CORRECT FOR ANY UNDERLYING BIAS IN DR. WOOLRIDGE'S HISTORICAL GROWTH RATES?

A. No. The median is simply the observation with an equal number of data values above and below. For odd-numbered samples, the median relies on only a single number, *e.g.*, the fifth number in a nine-number set. Reliance on the median value for a series of illogical values does not correct for the 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. As Dr. Woolridge noted in his testimony (Appendix A, p. 1), he is a founder and managing director of *ValuePro*, which is an online valuation service largely based on application of the DCF model. *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.[5]

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

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[5] http://www.valuepro.net/abtonline/abtonline.shtml.

> out of line, figure out where the Service may have strayed on a valuation, and correct it.[6]

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 his DCF model.

Q. DO YOU AGREE WITH MR. BAUDINO (P. 39) THAT YOU "ERRED" BY IGNORING VALUE LINE'S DPS GROWTH PROJECTIONS IN YOUR APPLICATION OF THE DCF MODEL?

A. No. As I explained in my direct testimony, specific trends in dividend policies for utilities and evidence from the investment community fully support my conclusion that earnings growth projections are likely to provide a superior guide to investors' expectations. Indeed, while Mr. Baudino suggests (p. 40) that dividend growth "must be considered," his own review of this information confirms my decision to exclude it. As shown on Mr. Baudino's Exhibit (RAB-7), the DPS growth rates for the firms in my Utility Proxy Group ranged from 1.0 percent to 13.0 percent. Even after excluding "aberrant or negative growth rates,"[7] Value Line's DPS growth rates for the firms in my Utility Proxy Group result in an average DCF cost of equity estimate of 8.92 percent, which falls far below even Mr. Baudino's downward biased 9.7 percent ROE recommendation.

Moreover, I disagree with Mr. Baudino's assertion (p. 39) that because Value Line's projected DPS growth rates "are widely available to investors," they can "reasonably be assumed to influence their expectation with respect to growth." Value Line publishes a wide variety of financial information, including growth rates

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[6] *Id.*

[7] Mr. Baudino failed to exclude growth rates of zero or 1.0 percent, despite the concerns noted on page 21 of his testimony.

in revenues and cash flows -- simply because a statistic is included in Value Line's report does not mean that investors would rely on it in determining their growth expectations. Indeed, Value Line makes a number of five and ten-year historical growth rates available to investors, including historical growth in DPS, which Mr. Baudino nevertheless rejected as inconsistent with investors' expectations.[8]

Q. IS THIS DOWNWARD BIAS ALSO APPARENT IN DR. WOOLRIDGE'S DPS GROWTH MEASURES?

A. Yes. Dr. Woolridge reported a median DPS growth rate for his electric proxy group based on Value Line's projections of 2.8 percent, which falls between 110 and 260 basis points lower than comparable values for his other forward-looking growth measures, and his median historical DPS growth rates were over 160 basis points below those indicated from his review of historical trends in EPS and BVPS.[9]

Similarly, the median projected DPS growth rate for Dr. Woolridge's gas proxy group was 3.0 percent, which falls between 100 and 260 basis points lower than comparable values for his other forward-looking growth measures.[10] As shown on page 3 of Exhibit JRW-10, almost one-half of the individual historical DPS growth rates reported by Dr. Woolridge for the companies in his gas proxy group were 1.5 percent or less and his median historical DPS growth rates were between 200 and 650 basis points below those indicated from his review of historical trends in EPS and BVPS. Combining a growth rate of 1.5 percent with Dr. Woolridge's dividend yield of 4.4 percent implies a DCF cost of equity of approximately 5.9

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[8] Baudino Direct at 21.
[9] Exhibit JRW-10, pp. 3-5.
[10] Exhibit JRW-10, pp. 4-5.

percent. Because this implied cost of equity is equal to the average yield on public utility bonds for April 2010, it is contrary to economic logic.[11]

Q. DO THE PROJECTED DPS GROWTH RATES FOR MR. BAUDINO'S PROXY GROUP EXHIBIT SIMILAR PROBLEMS?

A. Yes. As shown on page 1 of Mr. Baudino's Exhibit (RAB-4), DPS growth rates for four of the firms in his reference group were equal to 1.0 percent, and his average dividend growth rate of 3.97 percent was over 110 basis points below the growth rate indicated from his review of analysts' earnings growth projections. This mirrors the trend towards a more conservative payout ratio for electric utilities and the need to conserve financial resources to provide a hedge against heightened uncertainties. However, while utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, this is not necessarily indicative of investors' long-term growth expectations. In fact, as discussed in my direct testimony, growth in earnings is far more likely to provide a meaningful guideline to investors' expected growth rate.

Q. DO YOU AGREE THAT THE SCREENING CRITERIA MR. BAUDINO APPLIED RESULTED IN A REASONABLE GROWTH ESTIMATE?

A. No. While I certainly agree that it is appropriate to evaluate the reasonableness of inputs to the DCF model, I take issue with the specific criteria applied by Mr. Baudino. After a review of the individual growth rates for the companies in his reference group, Mr. Baudino speculated (p. 23) that no growth rate of 10 percent or above is reasonable. Mr. Baudino's "Method 3" results omitted all double-digit growth rates, as well as those below 1 percent. But the growth expectations relevant to the DCF model are those of investors, not his personal assessment, and he

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[11] Moody's Investors Service reported an average yield on public utility bonds for April 2010 of 5.87 percent. www.credittrends.com.

presented no evidence to support his claim that the growth expectations that investors build into current stock prices could never equal 10 percent or above. Moreover, while I agree with Mr. Baudino that growth rates below 1 percent cannot be considered reasonable, his criterion retains numerous other low-end growth estimates that produce illogical cost of equity estimates.

Q. HAVE OTHER REGULATORS APPROVED DCF ESTIMATES BASED ON GROWTH RATES THAT EXCEED SINGLE DIGITS?

A. Yes. For example, in 2002 the FERC approved an ROE zone of reasonableness of 9.21 percent to 15.96 percent for the utility participants in the Midwest Independent Transmission System Operator, Inc., with the high-end of the DCF range being based on a growth rate of 11.00 percent.[12] Similarly, in 2009 FERC approved an ROE based on DCF cost of equity estimates for a proxy group of fifteen companies that incorporated twelve individual growth rates ranging from 8.0 percent to 11.5 percent.[13] These authorized DCF results contradict Mr. Baudino's conclusion that double-digit growth rates are *per se* illogical.

Q. HOW CAN LOW-END DCF ESTIMATES BE EVALUATED?

A. As discussed in my direct testimony,[14] it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. Consistent with this principle, his DCF results must be adjusted to eliminate estimates that are determined to be outliers when compared against the yields available to investors from less risky utility bonds.

The Federal Energy Regulatory Commission ("FERC") evaluates DCF results against observable yields on long-term public utility debt and has recognized

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[12] *Midwest Independent Transmission System Operator, Inc.*, 99 FERC ¶ 63,011 at Appendix A (2002).
[13] *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 (2009).
[14] Avera Direct at 37-40.

that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. FERC noted in *Kern River Gas Transmission Company* that:

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt. [15]

The Commission upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible." [16] More recently, FERC affirmed that, "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[17]

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. As indicated in my direct testimony (pp. 38-40), it is generally expected that long-term interest rates will rise as the recession ends and the economy returns to a more normal pattern of growth. As shown in Table WEA-3 to my direct testimony, the increase in debt yields anticipated by IHS Global Insight and the Energy Information Administration imply an average triple-B bond yield of 7.26 percent for 2010, or 7.39 percent over the 5-year period 2010-2014.

Q. WHAT THEN IS A MORE REASONABLE APPLICATION OF MR. BAUDINO'S DCF ANALYSIS?

A. As explained in my direct testimony and demonstrated above, reference to trends in DPS result in distorted and illogical cost of equity estimates and should be ignored. Page 1 of Exhibit WEA-11 presents the individual cost of equity estimates produced by Mr. Baudino's DCF analysis based on projected EPS growth for each of the firms

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[15] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).
[16] *Id.*
[17] *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010).

in his proxy group. As highlighted on this exhibit, a considerable number of the cost of equity estimates resulting from Mr. Baudino's DCF method are not sufficiently greater than the yields investors would expect to earn by investing in long-term public utility debt, with many falling below the average yield on triple-B public utility bonds. As shown on page 1 of Exhibit WEA-11, excluding these illogical values results in an average DCF cost of equity for Mr. Baudino's proxy group of approximately 10.6 percent.

Q. WHAT COST OF EQUITY IS IMPLIED BY A MORE REASONABLE APPLICATION OF DR. WOOLRIDGE'S DCF ANALYSIS?

A. As shown on page 2 of Schedule WEA-11, screening Dr. Woolridge's DCF cost of equity estimates based on EPS growth rates to eliminate illogical, low-end outliers resulted in an implied cost of equity range of 10.5 percent to 11.4 percent for the firms in his electric proxy group, with the average being 11.0 percent. For Dr. Woolridge's group of gas utilities (page 3 of Exhibit WEA-11), the average DCF estimate was 10.0 percent.

Q. WHY DID YOU IGNORE THE INTERNAL, "BR" GROWTH RATES CALCULATED BY DR. WOOLRIDGE AND MR. BAUDINO?

A. The internal growth rates calculated by Dr. Woolridge and Mr. Baudino are downward biased because of computational errors and omissions.[18] These witnesses based their calculations of the internal, "br" retention growth rate on data from Value Line, which reports end-of-period results. If the rate of return, or "r" component of the internal 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

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[18] While Mr. Baudino calculated sustainable, "br" growth rates for the firms in his proxy group, his DCF analysis ignored these data.

common equity over the year. This downward bias, which has been recognized by regulators,[19] is illustrated in Table WEA-8 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."[20] 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:

TABLE WEA-8
BR + SV GROWTH RATE – AVERAGE RATE OF RETURN

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%**

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

Because Dr. Woolridge and Mr. Baudino failed to account for this reality in their analyses, the "internal" growth rates that they calculated are downward-biased.

Q. WHAT OTHER CONSIDERATION LEADS TO A DOWNWARD BIAS IN THE INTERNAL, "BR" GROWTH RATES OF DR. WOOLRIDGE AND MR. BAUDINO?

A. Both Dr. Woolridge and Mr. Baudino ignored the impact of additional issuances of common stock in their analyses 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.[21]

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 and Mr. Baudino failed to consider the incremental impact on growth results in

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

another downward bias to their "internal" growth rates, which should be given no weight.

Q. DID DR. WOOLRIDGE PRESENT ANY EVIDENCE THAT UNDERMINES YOUR REFERENCE TO STOCK PRICE GROWTH IN APPLYING THE DCF MODEL?

A. No. As indicated in my direct testimony,[22] I also examined expected growth in each utility's stock price based on Value Line's projections. Apart from his misguided claim that analysts' EPS growth rates are overly optimistic, which I address subsequently, Dr. Woolridge presented no evidence to dispute my DCF analyses based on expected growth in stock prices.

In fact, the DCF model assumes that investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation over their holding period. Expected growth in stock price is a central question posed by most investors when evaluating common stocks, and projected stock prices from investment advisory services such as Value Line are widely reported and available to investors. In other words, projected growth in stock price is directly relevant to an analysis of the future cash flows that investors expect to receive when they purchase common stocks and is entirely consistent with the underlying basis of the DCF model.

Under the assumptions required to derive the constant growth form of the DCF model, stock price, earnings, dividends, and book value are all expected to grow at the same rate. Dr. Myron Gordon noted in his seminal article, *The Cost of Capital to a Public Utility* (1974), that growth in stock price could serve as another guide to investors' growth expectations in the constant growth DCF model,

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[22] Avera Direct at 37.

observing that, "[T]he rate of growth in the price of a stock ... will respond to all of the factors mentioned above and, in addition, to the yield investors require on the share."[23] Similarly, *The Cost of Capital – A Practitioner's Guide*, published by the Society of Utility and Regulatory Financial Analysts, observed that under the assumptions of the DCF model, "The stock price grows proportionally to the growth rate."[24] My reference to expected growth in common stock prices is entirely consistent with this paradigm.

Q. DID MR. BAUDINO PROVIDE A LOGICAL RATIONALE FOR IGNORING EXPECTATIONS FOR STOCK PRICE APPRECIATION?

A. No. Mr. Baudino wrongly argues that looking to the cash flows that an investor may expect to receive through appreciation in share price is "inconsistent with the principle embodied in the DCF model." Mr. Baudino incorrectly asserts that the only appropriate cash flows to consider in applying the DCF model "are based on earnings and dividends, not on a forecast of what a company's stock price might be in a few years."[25]

As discussed above in response to Dr. Woolridge, however, the expectation for capital gains associated with share price appreciation is entirely consistent with the underpinnings of the DCF model. Of course, one need only listen in on Bloomberg or any one of a host of business programs to recognize that expectations for share price appreciation are highly relevant to investors' expectations regarding the rewards of stock ownership. In fact, Mr. Baudino's argument on page 37 that stock prices are not relevant cash flows to consider in the DCF model is rebutted by his own testimony:

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[23] Gordon, Myron J., "The Cost of Equity to a Public Utility," *MSU Public Utilities Studies* (1974).
[24] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997).
[25] Baudino Direct at 37.

> The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. *In the case of a common stock, those future cash flows take the form of dividends and appreciation in stock price.*[26]

Q. WHAT ABOUT MR. BAUDINO'S OBSERVATION (P. 37) THAT STOCK PRICES ARE "INFLUENCED BY THE VICISSITDES OF THE MARKET?"

A. I agree that stock price projections do respond to changes in expectations regarding the outlook for the economy, capital market conditions, firm-specific factors, and a host of other considerations relevant to investors. In fact, the notion that stock prices capture all relevant information available to investors is the bedrock of modern capital market theory. But the fact that projections for share price appreciation change in response to economic and market cycles does not impugn the usefulness of price growth to serve as a gauge of investors' future expectations when they purchase common stock.

Q. WHAT DCF COST OF EQUITY IS INDICATED FOR THE PROXY GROUPS OF MR. BAUDINO AND DR. WOOLRIDGE BASED ON PROJECTED GROWTH IN STOCK PRICES?

A. As shown on page 1 of Exhibit WEA-12, growth rates implied by Value Line's stock price projections for Mr. Baudino's proxy firms result in an average DCF cost of equity of suggests a cost of equity of 10.5 percent. As shown on page 2 of Exhibit WEA-12, applying the DCF model based on the price growth expected for the firms in Dr. Woolridge's electric proxy group suggests a cost of equity of 11.4 percent, or 10.3 percent for his gas proxy group (page 3 of Exhibit WEA-12).

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[26] Baudino Direct at 15 (emphasis added).

Q. WHAT DO YOU CONCLUDE BASED ON YOUR REVIEW OF THE DCF ANALYSES PRESENTED BY DR. WOOLRIDGE AND MR. BAUDINO?

A. Historical growth rates and trends in DPS are distorted by fundamental changes in industry financial policies and Dr. Woolridge and Mr. Baudino failed to evaluate the underlying reasonableness of individual growth rates. In addition, the calculation's used to arrive at the internal growth rates reported by Dr. Woolridge and Mr. Baudino are flawed and incomplete. As a result, their DCF cost of equity estimates are biased downward and fail to reflect investors' required rate of return.Correcting their analyses to remove illogical values and incorporate alternative growth measures more indicative of investors' expectations demonstrates that the 9.0 - 9.5 percent and 9.7 percent recommendations of Dr. Woolridge and Mr. Baudino, respectively, are far too low to be considered credible.

III. CRITICISMS OF ANALYSTS' GROWTH RATES ARE MISGUIDED

Q. SHOULD THE KPSC GIVE ANY CREDENCE TO DR. WOOLRIDGE'S ALLEGATIONS THAT PROJECTED EPS GROWTH RATES ARE BIASED?

A. No. These arguments were addressed on pages 34-35 of my direct testimony. 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.

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.[27]

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

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

analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the 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 (as shown on Exhibits WEA-2 and WEA-4, I also examined the "br+sv", sustainable growth rates for the companies in my proxy groups), 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.[28] 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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[28] 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.[29]

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.[30]

Similarly, while Dr. Woolridge cites a 2008 *Wall Street Journal* ("WSJ") article, an April 26, 2010 study reported in this publication contradicts his position. The WSJ concluded that analysts' earnings forecasts "are actually too pessimistic when it comes to predicting company earnings, particularly in the wake of recession."[31] The WSJ indicated that "analysts' expectations will continue to be trumped by better results as the current reporting season progresses,"[32] suggesting that current growth measures are more likely to be too low than too high.

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

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

[30] 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).

[31] Denning, Liam, "Wall Street's Missed Expectations," *Wall Street Journal* at C8 (Apr. 26, 2010).

[32] *Id.*

growth rate estimates are overly optimistic, based on just such a historical comparison.[33] 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 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."[34] 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.[35]

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

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

[34] Boselovic, Len, "Study Finds Analysts' Forecasts Have Been Too Sunny," *Pittsburgh Post-Gazette* (Mar. 30, 2008).

[35] Harris, Robert S. and Marston, Felicia C., "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," *Journal of Applied Finance* 11 (2001) at 8.

the analysts' forecasts prove to be wrong in hindsight.[36] As Dr. Woolridge granted with respect to Value Line's projections, for example:

> If investors rely on these forecasts, then they are a factor in gauging future growth rate expectations.[37]

Q DID DR. WOOLRIDGE PROVIDE ANY MEANINGFUL SUPPORT FOR HIS ALLEGATION THAT VALUE LINE FORECASTS ARE "OVERLY OPTIMISTIC"?

A. No. Dr. Woolridge asserted his belief (p. 68) that Value Line projections have "a decidedly positive bias," based only on his personal belief that Value Line does not report a sufficient number of negative growth rates. But as Mr. Baudino noted (p. 22), negative growth rates are inconsistent with the assumptions of the DCF model and not likely to be representative of investors' expectations. 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".[38]

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[36] 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.

[37] Response to KPSC Question 7.

[38] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at 8-28.

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 (p. 64).[39]

IV. UTILITIES ARE NOT AN INVESTMENT ISLAND

Q. What is the fallacy underlying Dr. Woolridge's and Mr. Baudino's rejection of any reference to non-utility companies in evaluating a fair ROE for LGE?

A. Dr. Woolridge and Mr. Baudino dismiss out of hand my analysis of the cost of equity for non-utility firms based on the claim that utilities are profoundly different and therefore less risky from other companies in the economy. 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 return to be allowed for rate-setting purposes is wrong and inconsistent with reality, investor behavior, and the *Bluefield* and *Hope* decisions. 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. True enough, utilities are sheltered from competition, but they undertake other obligations and lose the ability to set their own prices and decide when to exit a market. The Supreme Court has

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[39] Tsao, Amy, "The New Era of Indie Research," *Business Week Online Edition* (June 12, 2003).

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.[40]

Consistent with this view, Mr. Baudino noted (pp. 12-13) that the notion of "opportunity cost" underlies the Supreme Court's economic standards, and that:

> One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. ... That alternative could have been another utility stock, a utility bond, <u>a mutual fund</u>, a money market fund, <u>or any other number of investment vehicles</u>. (emphasis added)

As Mr. Baudino correctly observed (p. 13), "The key determinant in deciding whether to invest, however, is based on comparative levels of risk," and he concluded, "[T]he task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms." In other words, Mr. Baudino recognized that investors gauge their required returns from utilities against those available from non-utility firms of comparable risk. My reference to a comparable-risk Non-Utility Proxy Group is entirely consistent with the guidance of the Supreme Court and the principles outlined in Mr. Baudino's own testimony.

Q. Do utilities have to compete with non-regulated firms for capital?

A. Most certainly. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives, which according to Dr. Woolridge include, "other enterprises having comparable risks."[41] Clearly the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment and there are a plethora of "other enterprises" available to investors beyond those in the utility industry.

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[40] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[41] Woolridge Direct at 21.

Q. DID MR. BAUDINO OR DR. WOOLRIDGE PRESENT ANY OBJECTIVE EVIDENCE TO SUPPORT THEIR CONTENTION THAT YOUR NON-UTILITY PROXY GROUP IS RISKIER THAN LGE OR YOUR UTILITY PROXY GROUPS?

A. No. Dr. Woolridge presented no meaningful evidence to rebut the results for my Non-Utility Proxy Group; rather, he simply observed that my Non-Utility Proxy Group "includes such companies as Abbott Labs, Coca-Cola, General Mills, Hewlett Packard, IBM, Johnson & Johnson, McDonalds, Medtronic, Microsoft, and NIKE," and concluded these companies are "vastly different" from utilities and do not operate in a "highly regulated environment."[42] Similarly, apart from sweeping generalizations about the risk differences between regulated and non-regulated companies, Mr. Baudino provided no support whatsoever for his contention that my Non-Utility Proxy Group is riskier than LGE or my Utility Proxy Group.

My Non-Utility Proxy Group is comprised of 69 of the best-known and most stable corporations in America and has risk measures that are comparable to, or less than the proxy groups of gas and combination utilities referenced in my analyses.[43] While these companies do not have the regulatory protections that utilities have, neither do they bear the burdens of losing control over their prices, undertaking the obligation to serve, and having to invest in infrastructure even in unfavorable market conditions. LGE can't relocate its service territory to an area with greater customer density or higher prospects for economic growth, postpone capital spending necessary to maintain reliability and accommodate growth, or abandon customers when turmoil roils energy or capital markets.

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[42] Woolridge Direct at 56.
[43] Avera Direct at Table WEA-2.

Consider Mr. Baudino's statement that utilities "have protected markets … enjoy full recovery of prudently incurred costs, and may increase their rates to cover increases in costs."[44] Based on this, Mr. Baudino summarily concluded, "Obviously, the non-utility companies have higher overall risk structures." In fact, however, investors are quite aware that utilities are <u>not</u> guaranteed recovery of prudent costs and that there are many instances in which utilities are unable to increase rates to fully recoup reasonable and necessary costs, resulting in an inability to earn the allowed rate of return on invested capital. 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 such as UniSource with frozen rates, a debt-to-capital ratio of 73 percent, and a junk bond credit rating, versus (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 0.60, the investment community would undoubtedly regard Wal-Mart as a less risky alternative to the utility included in Dr. Woolridge's electric proxy group.

Q. DOES A COMPARISON OF OBJECTIVE RISK MEASURES SUPPORT DR. WOOLRIDGE'S AND MR. BAUDINO'S CONCLUSIONS REGARDING THE RELATIVE RISK OF YOUR NON-UTILITY PROXY GROUP?

A. No. In fact, the objective risk measures specifically cited by Mr. Baudino as being relevant indicia of overall investment risks contradict his assertions and those of Dr. Woolridge. As noted earlier, Mr. Baudino testified that bond ratings reflect a

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[44] Baudino Direct at 36.

detailed and comprehensive analysis of the key factors contributing to a firm's overall investment risk, concluding (p. 14), "Bond ratings are tools that investors use to assess the risk comparability of firms." Contradicting Mr. Baudino's unsupported assertion (p. 37) that the companies in my Non-Utility Proxy Group "have higher overall risk structures," my direct testimony noted that the average corporate credit rating for the Non-Utility Proxy Group of "A" is <u>higher</u> than the "BBB+" average for the Utility Proxy Group and LGE. In fact, the review of objective indicators of investment risk presented in my direct testimony (Table WEA-2), which consider the impact of competition and market share, demonstrated that, if anything, the Non-Utility Proxy Group could be considered somewhat <u>less</u> risky in the minds of investors than the common stocks of the proxy group of utilities.

Q. Does Dr. Woolridge apparently consider non-utility stock returns relevant to determining the cost of capital?

A. Indeed he does. Dr. Woolridge cites many studies of past and expected stock market returns in his testimony, including a list of over 30 studies included on page 5 of Exhibit JRW-11. *Not one* of these studies is limited to utilities, and all include a predominance of non-utility common stocks, e.g., Standard & Poor's 500 Index. Moreover, while Dr. Woolridge references a study of industry betas done at New York University (p. 21) that suggests utilities have lower risks than the average firm in the non-regulated sector, this establishes nothing more than the obvious – while some unregulated firms have higher risks than utilities, others have lower risks. As documented in my direct testimony, the firms in my Non-Utility Proxy Group are also in the lower ranges of risk as measured by objective, widely referenced benchmarks.

Q. Would it be consistent with the *Bluefield* and *Hope* cases to disregard required returns for non-utility companies?

A. No. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Indeed, if the requirement is business in the same part of the country and the utility has the exclusive franchise, then the Court could only be referring to non-utility businesses and any nearby utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Indeed, in teaching regulatory policy I usually observe that in the early applications of the comparable earnings approach, utilities were explicitly eliminated due to a concern about circularity. In other words, soon after the *Hope* decision regulatory commissions did not want to get involved in circular logic by looking to the returns of utilities that were established by the same or similar regulatory commissions in the same geographic region. To avoid circularity, regulators looked only to the returns of non-utility companies. Incidentally, the requirement in the *Bluefield* case of restricting the comparable group to the geographic region is often overlooked in the academic literature. It is interesting to note that virtually all of the firms in my Non-Utility Proxy Group have a significant presence in Kentucky.

Q. Does consideration of the results for the Non-Utility Proxy Group make the estimation of the cost of equity using the DCF model more reliable?

A. Yes. The estimates of growth from the DCF model depend on analysts' forecasts, or in the case of Dr. Woolridge, historical performance. It is possible for utility growth rates to be distorted by historical trends in the industry (e.g., changes in payout ratios) or the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. For example, Value Line recently observed that near-term growth rates understate the longer-term expectations for gas utilities:

> Natural Gas Utility stocks have fallen near the bottom of our Industry spectrum for Timeliness. Accordingly, short-term investors would probably do best to find a group with better prospects over the coming six to 12 months. Longer-term, we expect these businesses to rebound. An improved economic environment, coupled with stronger pricing, should boost results across this sector over the coming years.[45]

Because the Non-Utility Proxy Group includes low risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

V. NO BASIS TO IGNORE RETURNS ON BOOK VALUE

Q. IS THERE ANY BASIS FOR THE CONTENTION OF DR. WOOLRIDGE AND MR. BAUDINO THAT THE EXPECTED EARNINGS APPROACH IS NOT A VALID ROE BENCHMARK?

A. No. My expected earnings approach is predicated on the comparable earnings test, which developed as a direct result of the Supreme Court decisions in *Bluefield* and *Hope*. From my understanding as a regulatory economist, not as a legal interpretation, these cases required that a utility be allowed an opportunity to earn

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[45] The Value Line Investment Survey at 445 (Mar. 12, 2010).

the same return as companies of comparable risk. That is, the cases recognized that a utility must compete with other companies (including non-utilities) for capital.

Q. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. As Mr. Baudino recognized (p. 12), economists refer to the returns that an investor must forgo by not being invested in the next best alternative as "opportunity costs".

Q. WHAT ARE THE IMPLICATIONS OF SETTING AN ALLOWED ROE BELOW THE RETURNS AVAILABLE FROM OTHER INVESTMENTS OF COMPARABLE RISK?

A. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. In this situation the government is effectively taking the value of investors' capital without adequate compensation.

Q. HOW IS THE COMPARISON OF OPPORTUNITY COSTS TYPICALLY IMPLEMENTED?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Q. DR. WOOLRIDGE (P. 5) CLAIMS THE EARNINGS ON BOOK VALUE APPROACH "HAS NOT BEEN USED BY REGULATORY COMMISSIONS FOR YEARS." IS THAT YOUR EXPERIENCE?

A. Not at all. While Dr. Woolridge is correct that this method predominated before the DCF model became fashionable with academic experts, I continue to encounter it around the country. Indeed, the Virginia State Corporation Commission ("VSCC") is required by statute (Virginia Code 56-585) to consider the earned returns on book value of electric utilities in its region. In an order issued on July 14, 2009 the VSCC confirmed the relevance of earned book returns in Docket PUE-2009-00019 for Virginia Electric and Power Company. Another example is Ms. Terri Carlock, the long-time financial analyst for the Idaho Public Utilities Commission. She has consistently presented evidence on book earnings for decades, and Idaho regulators continue to confirm the relevance of return on book equity evidence.[46]

Perhaps the most ardent proponent of earned returns as a benchmark for fair ROE is David C. Parcell, who frequently appears as a witness for regulatory agencies and other intervenors. Mr. Parcell literally "wrote the book" for the Society of Utility and Regulatory Financial Analysts.[47] Mr. Parcell called the comparable earnings approach the "granddaddy" of cost of equity methods.[48] He also points out that the amount of subjective judgment required to implement this

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[46] The comparable earnings approach was identified as a favored method in determining the allowed ROE for 24 of the agencies surveyed in NARUC's compilation of regulatory policy. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996). In my experience, while a few Commissions have explicitly rejected comparable earnings, most regard it as a useful tool.

[47] Parcell, David C., *The Cost of Capital – A Practitioner's Guide* (1997).

[48] *Id.* at 7-1.

method is "minimal", particularly when compared to the DCF and CAPM methods.[49] Mr. Parcell also notes that this method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases.[50]

Q. DO YOU AGREE WITH MR. BAUDINO (P. 42) THAT A METHODOLOOGY MUST BE "MARKET-BASED" TO BE USEFUL IN EVALUATING INVESTORS' OPPORTUNITY COSTS?

A. No. While I agree that market-based models are certainly important tools in estimating investors' required rate of return, this in no way invalidates the usefulness of the expected earnings approach. In fact, this is one of its advantages.

It is a very simple, conceptual principal that when evaluating two investments of comparable risk, investors will choose the alternative with the higher expected return. If LGE is only allowed the opportunity to earn 9.0 - 9.5 percent or 9.7 percent return on the book value of its equity investment, as recommended by Dr. Woolridge and Mr. Baudino, while the comparable-risk utilities in my proxy group are expected to earn an average of 11.4 percent,[51] the implications are clear -- LGE's investors will be denied the ability to earn their opportunity cost.

Moreover, regulators do not set the returns that investors earn in the capital markets – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar

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[49] *Id.* at 7-3.
[50] *Id.*
[51] Avera Direct at Exhibit WEA-8.

in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. WHAT ROE IS IMPLIED IF THE EXPECTED EARNINGS APPROACH IS APPLIED TO THE COMPANIES IN THE PROXY GROUPS OF DR. WOOLRIDGE AND MR. BAUDINO?

A. As shown on page 1 of Exhibit WEA-13, the expected earnings approach implied an average cost of equity for the utilities in Mr. Baudino's proxy group of 11.2 percent. Meanwhile, page 2 of Exhibit WEA-13 shows that the expected book return on equity for Dr. Woolridge's electric proxy group is 10.9 percent, with the average expected return for his gas proxy group being 11.9 percent (page 3 of Exhibit WEA-13). These book return estimates are an "apples to apples" comparison to the 9.7 percent and 9.0 - 9.5 percent recommended ROEs of Mr. Baudino and Dr. Woolridge, respectively.

Q. WHAT WOULD BE THE EFFECT OF AUTHORIZING A BOOK RETURN FOR LGE THAT IS SO FAR BELOW THE AVERAGE EARNINGS OF THE UTILITIES THAT MR. BAUDINO AND DR. WOOLRIDGE CLAIM ARE COMPARABLE?

A Plain and simple, LGE will find it difficult to compete for investors' capital and the Company would not be earning up to the Bluefield standard of comparable earnings:

> A public utility is entitled to such rates as will permit it to earn on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business

> undertakings which are attended by corresponding risks and uncertainties.[52]

Q. WHAT IS THE RELEVANCE OF DR. WOOLRIDGE'S DISCUSSION OF MARKET-TO-BOOK RATIOS (PP. 15-17 & 69) TO THE DEVIATION BETWEEN HIS RECOMMENDED ROE AND THE EARNED RETURNS EXPECTED FOR COMPARABLE UTILITIES?

A. Based on his testimony here and in previous cases, I understand that Dr. Woolridge is trying to argue that utility earnings are generally too high because the market-to-book ratios generally exceed one. He wants the KPSC to sacrifice LGE's financial strength to favor a theoretical ideal of market-to-book ratios equaling unity. The KPSC does not regulate utility stock market prices, and as discussed below, there are many leaps between his economic theory and reality. But if the theory is correct, then Dr. Woolridge is asking the KPSC to order a return that would almost certainly lead to a capital loss on the value of LGE's investment. From an economic perspective, such an action would take the value of LGE's property without compensation, the kind of behavior that upset the American colonists against the English Crown.

Q. DO YOU AGREE WITH DR. WOOLRIDGE THAT IT IS NECESSARY TO EXAMINE MARKET-TO-BOOK RATIOS IN APPLYING THE EXPECTED EARNINGS APPROACH?

A. No. Traditional applications of the expected earnings approach do not involve a market-to-book adjustment. I have never made a market-to-book adjustment, nor is such an adjustment recommended in recognized texts such as *Regulatory Finance: Utilities' Cost of Capital.*[53]

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[52] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923).

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

Q. IS THERE A CLEAR LINK BETWEEN MARKET-TO-BOOK RATIOS FOR ELECTRIC UTILITIES AND ALLOWED RATES OF RETURN?

A. No. Underlying Dr. Woolridge's criticism is the supposition that regulators should set a required rate of return to produce a market-to-book value of approximately 1.0. This is fallacious. For example, *Regulatory Finance: Utilities Cost of Capital* noted that:

> 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 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.[54]

With market-to-book ratios for most utilities above 1.0, Dr. Woolridge is suggesting that, unless book value grows rapidly, regulators should establish equity returns that will cause share prices to fall. Given the regulatory imperative of preserving a utility's ability to attract capital, this would be a truly nonsensical result.

Q. IS THERE ANYTHING UNUSUAL ABOUT A STOCK PRICE EXCEEDING BOOK VALUE?

A. No. In fact the majority of stocks currently sell substantially above book value. For example, Value Line reports that over 1,300 of the approximately 1,700 stocks it follows (including utilities and other industries) sell for prices in excess of book value.[55]

Moreover, regulators previously recognized the fallacy of relying on market-to-book ratios in evaluating cost of equity estimates. For example, the Presiding Judge in *Orange & Rockland* concluded, and the FERC affirmed that:

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[54] *Id.* at 256.
[55] www.valueline.com (retrieved Apr. 29, 2010).

> The presumption that a market-to-book ratio greater than 1.0 will destroy the efficacy of the DCF formula disregards the realities of the market place principally because the market-to-book ratio is rarely equal to 1.0.[56]

The Initial Decision found that there was no support in Commission precedent for the use of market-to-book ratios to adjust market derived cost of equity estimates based on the DCF model and concluded that such arguments were to be treated as "academic rhetoric" unworthy of consideration.

Q. WHAT OTHER EVIDENCE INDICATES THAT THE RECOMMENDATIONS OF MR. BAUDINO AND DR. WOOLRIDGE ARE INSUFFICIENT TO MEET REGULATORY STANDARDS?

A. Reference to allowed rates of return for other utilities provides one useful guideline that can be used to assess the extent to which the 9.7 percent and 9.0 - 9.5 percent ROE recommendations of Mr. Baudino and Dr. Woolridge are comparable and sufficient. As shown on page 1 of Exhibit WEA-14, data from the April 2010 *AUS Monthly Utility Report* (a source relied on by Dr. Woolridge and Mr. Baudino) indicates that the average authorized ROE for the firms in Mr. Baudino's proxy group is 10.64 percent, or 94 basis points higher than his recommendation for LGE.

With respect to the group of electric utilities that Dr. Woolridge concluded were most comparable to LGE's jurisdictional utility operations, as shown on page 2 of Exhibit WEA-14, these firms are presently authorized an average rate of return on equity of 10.7 percent, or 120basis points more than Dr. Woolridge's ROE recommendation. Similarly, the average authorized return for Dr. Woolridge's gas proxy group (Page 3 of Exhibit WEA-14) was 10.45 percent. It is unreasonable to suppose that investors would be attracted by Dr. Woolridge's or Mr. Baudino's

[56] *Orange & Rockland Utilities, Inc.*, Initial Decision, 40 FERC ¶ 63,053, 1987 WL 118,352 (F.E.R.C.).

recommendations for LGE, which fall significantly below the allowed returns for other utilities they consider to be comparable.

Q. DOES THE TESTIMONY OF MR. PRISCO PRESENT A SOUND BASIS ON WHICH TO ESTABLISH AN ROE FOR LGE?

A. No. Mr. Prisco recommended a 10.35 percent ROE (p. 12), which was based on authorized rates of return adopted during the test period used for LGE's rate filings. While I agree that Mr. Prisco's testimony provides further confirmation that the recommendations of Mr. Baudino and Dr. Woolridge are biased downward, it does not represent a reasoned approach to estimating investors' current ROE. Mr. Prisco made no attempt to estimate investors' required rate of return and he conducted no independent analyses. Aside from the fact that Mr. Prisco did not employ any of the methods customarily relied on to estimate the cost of equity, he made no attempt to consider the relative risks of LGE, which is fundamental to a determination of a fair ROE.

VI. CAPM RESULTS SHOULD BE DISREGARDED

Q. DID EITHER DR. WOOLRIDGE OR MR. BAUDINO RELY ON THEIR CAPM RESULTS IN ARRIVING AT THEIR RECOMMENDATIONS IN THIS CASE?

A. No. Dr. Woolridge ignored his 7.8 percent CAPM cost of equity estimate in arriving at his 9.0 - 9.5 percent recommendation, which is at the top of his 7.8 percent to 9.5 percent cost of equity range. Dr. Woolridge noted that he gave "primary weight" to the DCF model,[57] and he concluded that the CAPM provides "a less reliable indication of equity cost rates for public utilities."[58] Similarly, as Mr. Baudino

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[57] Woolridge Direct at 3.
[58] Woolridge Direct at 22-23.

noted,[59] his ROE recommendation was based solely on cost of equity estimates implied by his application of the DCF model and ignored his CAPM results entirely.

Q. IS THERE GOOD REASON TO ENTIRELY DISREGARD THE RESULTS OF THE CAPM ANALYSES PRESENTED BY DR. WOOLRIDGE AND MR. BAUDINO?

A. Yes. As discussed in my direct testimony,[60] applying the CAPM is complicated by the impact of the recent capital market turmoil and recession on investors' risk perceptions and required returns. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors sought a safe haven in U.S. government bonds and this "flight to safety" pushed Treasury yields significantly lower while yield spreads for corporate debt widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased. This is simply not the time for the KPSC to give any weight to the CAPM, irrespective of methodology.

Meanwhile, the backward-looking, historical approaches employed by Dr. Woolridge and Mr. Baudino incorrectly assume 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 past average. At no time in recent history has the fallacy of this assumption been demonstrated more concretely. This incongruity between investors' current expectations and requirements and historical

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[59] Baudino Direct at 3.

[60] Avera Direct at 44-46.

risk premiums is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently.

As a result, there is every indication that the historical CAPM approach fails to fully reflect the risk perceptions of real-world investors in today's capital markets, which would violate the standards underlying a fair rate of return by failing to provide an opportunity to earn a return commensurate with other investments of comparable risk. As the Staff of the Florida Public Service Commission recently concluded:

> [R]ecognizing the impact the Federal Government's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, staff believes models that relate the investor-required return on equity to the yield on government securities, such as the CAPM approach, produce less reliable estimates of the ROE at this time.[61]

While I agree with the decision of Dr. Woolridge and Mr. Baudino to give no weight to their CAPM results, for completeness my rebuttal testimony nevertheless addresses the major flaws associated with their applications of this approach.

Q. WHAT IS THE FUNDAMENTAL PROBLEM ASSOCIATED WITH THE HISTORICAL APPROACHES USED BY DR. WOOLRIDGE AND MR. BAUDINO 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 reflect the expectations of actual investors in the market. Dr. Woolridge recognized that "ex post returns are not the same as ex ante expectations" and noted that "market

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[61] *Staff Recommendation for Docket No. 080677-EI - Petition for increase in rates by Florida Power & Light Company*, at p. 280 (Dec. 23, 2009).

risk premiums can change over time; increasing when investors become more risk-averse."[62] Nevertheless, his application of the CAPM method was based entirely on *historical* – not projected – rates of return, as was the CAPM method presented on Mr. Baudino's Exhibit (RAB-6). Morningstar recognized the primacy of current expectations:

> 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.[63]

Because the backward-looking analyses of Dr. Woolridge and Mr. Baudino ignore the returns investors are currently requiring in the capital markets, the resulting CAPM estimates significantly understate investors' required rate of return.

Q. IS THERE EVIDENCE THAT THE STUDIES REFERENCED BY DR. WOOLRIDGE 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 and contradict his own testimony. As shown on page 5 of Dr. Woolridge's Exhibit JRW-11, 25 of the historical studies included in Dr. Woolridge's assessment found market equity risk premiums of approximately 4.75 percent or below. But combining a market equity risk premium of 4.75 percent with Dr. Woolridge's 4.75 percent risk-free rate results in an indicated cost of equity for the market as a whole of 9.5 percent, which is *equal* to Dr. Woolridge's ROE recommendation for LGE's electric utility operations in this case. Many of his other benchmarks for the market rate of return fall *below* the anemic cost of equity he

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[62] Woolridge Direct at 42.
[63] Morningstar, *Ibbotson SBBI, 2008 Valuation Yearbook* at 23.

recommends for LGE. For example, Dr. Woolridge conjures a market rate of return of 7.00 percent based on his "building blocks" approach,[64] which falls 185 basis points below his recommended ROE in this case,

Meanwhile, after noting that beta is the only relevant measure of investment risk under modern capital market theory, Dr. Woolridge concluded that his comparison of beta values (Exhibit JRW-8) indicates that investors' required return on the market as a whole should exceed the cost of equity for utilities.[65] Based on Dr. Woolridge's own logic, it follows that a market rate of return that does not exceed his own downward biased ROE recommendation has no relation to the current expectations of real-world investors. The fact that much of his CAPM "evidence" violates the risk-return tradeoff that is fundamental to finance and illustrates the frailty of Dr. Woolridge's analyses.

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

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[64] Woolridge Direct at 47. Similarly, Dr. Woolridge reported market rates of return of 7.27 percent and 7.62 percent from the selected surveys cited at pages 48-49 of his testimony.

[65] Woolridge Direct at 21.

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 the return investors currently expect to earn on money invested today in the risky market portfolio versus the risk-free U.S. Treasury alternative.

Q. WERE DR. WOOLRIDGE OR MR. BAUDINO JUSTIFIED IN RELYING ON GEOMETRIC MEANS AS A MEASURE OF AVERAGE RATE OF RETURN WHEN APPLYING THE HISTORICAL CAPM?

A. No. 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.[66]

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.[67]

I certainly agree that both geometric and arithmetic means are useful, since my Ph.D. dissertation was on the usefulness of the geometric mean.[68] 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 deeply into finance theory to see why the arithmetic mean is more consistent with the facts of this case. The KPSC is not setting a constant return that LGE is guaranteed to earn over a long

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[66] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports* AT 275 (1994) (emphasis added).
[67] Morningstar, *Ibbotson SBBI 2008 Valuation Yearbook* at 77.
[68] William E. Avera, *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice* (1972).

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.[69] Just as importantly, by relying directly on expectations and estimates of investors' required rate of return, as incorporated in the CAPM analysis presented in my direct testimony, there is no need to debate the merits of geometric versus arithmetic means, because neither is required to apply this forward-looking approach.

Q. WHAT DOES THIS IMPLY WITH RESPECT TO DR. WOOLRIDGE'S AND MR. BAUDINO'S CAPM RESULTS?

A. For a variable series, such as stock returns, the geometric average will <u>always</u> be less than the arithmetic average. Accordingly, reference to geometric average rates of return provides yet another element of built-in downward bias to the CAPM applications of Dr. Woolridge and Mr. Baudino.

Q. WHAT ABOUT DR. WOOLRIDGE'S VIEW THAT THE MARKET RETURN USED IN YOUR FORWARD-LOOKING CAPM ANALYSIS (EXHIBITS WEA-6 AND WEA-7) 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

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[69] DeFusco, Richard A., Dennis W. McLeavey, Jerald E. Pinto, and David E. Runkle, *Quantitative Investment Analysis*, John Wiley & Sons, Inc. (2007) at 128.

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 growth rates used in 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 4 of Dr. Woolridge's Exhibit JRW-11 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.

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, 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 9.2 percent expected growth rate and resulting 11.9 percent market return that I used to apply the CAPM are "overstated," his own exhibits and sources contradict his personal view. Consider Exhibit JRW-15, for example, which presents historical earnings for the S&P 500. In 21 of the years included in Dr. Woolridge's table, growth in earnings exceeded the 9.2 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 11.9 percent forward-looking estimate used in my CAPM analysis in over one-half of those years, in many cases by a considerable margin.[70]

Q. IS THERE ANY REASON THAT THE GROWTH RATES USED IN A DCF ANALYSIS MUST BE CONSTRAINED BY THE OVERALL GROWTH OF THE ECONOMY, AS DR. WOOLRIDGE ASSERTS (P. 71)?

A. No. Dr. Woolridge suggested that it would be illogical for investors to expect long-term growth for the market as a whole to exceed the rate of growth of the economy. The real issue here is not Dr. Woolridge's sense of logic, but rather the expectations of investors. Few investors are likely to adopt Dr. Woolridge's theoretical approach and growth in excess of the economy as a whole is consistent with investors' expectations.[71] Indeed, Multex Investor, a publisher of financial research and investment information that is now an arm of Thomson Reuters, advised that "all equity investors … should look for growth rates that are at least as strong as growth of Real GDP and Inflation."[72] As a practical matter, investors do not look to that distant horizon where all companies must grow at the rate of the economy. Not only is it impossible to predict the distant future, it simply doesn't matter. In terms of the DCF model, the present value of cash flows in far distant years – beyond the foreseeable future – is so small as to have little effect on investment decisions today.

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[70] Morningstar, *Ibbotson SBBI 2010 Valuation Yearbook* at Table B-1.

[71] As discussed earlier, the fact that Dr. Woolridge's DCF analysis considered historical growth rates below single-digits provides further confirmation that his results fail to reflect the views of real-world investors.

[72] www.multexinvestor.com

Q. DO THE SHORT-TERM TREASURY BILL RATES REFERENCED BY MR. BAUDINO (P. 30) PROVIDE AN APPROPRIATE BASIS TO ESTIMATE THE COST OF EQUITY USING THE CAPM?

A. No. Unlike debt instruments, common equity is a perpetuity and as a result, any application of the CAPM to estimate the return that investors require must be predicated on their expectations for the firm's long-term risks and prospects. This does not mean that every investor will buy and hold a particular common stock into perpetuity. Rather, it recognizes that even an investor with a relatively short holding period will consider the long-term, because of its influence on the price that he or she ultimately receives from the stock when it is sold. This is also the basic assumption underpinning the DCF model, which in theory considers the present value of all future dividends expected to be received by a share of stock.

Shannon P. Pratt, a leading authority in business valuation and cost of capital, recognized that the cost of equity is a long-term cost of capital and that the appropriate instrument to use in applying the CAPM is a long-term bond:

> The consensus of financial analysts today is to use the 20-year U.S. Treasury yield to maturity as of the effective data of valuation for the following reasons:
>
> - It most closely matches the often-assumed perpetual lifetime horizon of an equity investment.
> - The longest-term yields to maturity fluctuate considerably less than short-term rates and thus are less likely to introduce unwarranted short-term distortions into the actual cost of capital.
> - People generally are willing to recognize and accept the fact that the maturity risk is impounded into this base, or otherwise risk-free rate.

- It matches the longest-term bond over which the equity risk premium in measured in the Ibbotson Associates data series.[73]

Similarly, in applying the CAPM Ibbotson Associates recognized that the cost of equity is a long-term cost of capital and the appropriate interest rate to use is a long-term bond yield:

> The horizon of the chosen Treasury security should match the horizon of whatever is being valued. ... Note that the horizon is a function of the investment, not the investor. If an investor plans to hold a stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.[74]

Accordingly, proper application of the CAPM should focus on long-term government bonds and analyses based on 5-year Treasury notes should be ignored.

Q. MR. BAUDINO (PP. 41-42) POINTS OUT THAT YOU HAVE PREVIOUSLY APPLIED THE CAPM USING HISTORICAL DATA. IS THERE ANY INCONSISTENCY IN YOUR POSITION?

A. None whatsoever. While reference to historical data represents one way to apply the CAPM, these realized rates of return reflect, at best, an indirect estimate of investors' current requirements. I have consistently observed that, in order to accurately estimate required returns, the CAPM must be applied using data that reflect the expectations of actual investors.

In other words, my position has been, and continues to be, that the only appropriate application of the CAPM is one based on the forward-looking expectations of investors. As I recognized, while historical data are sometimes referenced as a proxy for investors' expectations, they are a poor substitute for the

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[73] Pratt, Shannon P., *Cost of Capital, Estimation and Applications* at 60 (1998).

[74] Ibbotson Associates, *2003 Yearbook* (Valuation Edition) at 53.

forward-looking approach presented in my direct testimony. Similarly, Mr. Baudino concluded (p. 29), "There is no real support for the proposition that an unchanging, mechanically applied historical risk premium is representative of current investor expectations and return requirements."

Q. IS THERE ANY MERIT TO MR. BAUDINO'S ARGUMENT (P. 40-41) THAT YOUR ANALYSIS OF THE MARKET RATE OF RETURN SHOULD NOT HAVE BEEN LIMITED SOLELY TO THE DIVIDEND PAYING FIRMS IN THE S&P 500?

A. No. As Mr. Baudino recognized (p. 15-16), under the constant growth form of the DCF model, investors' required rate of return is computed as the sum of the dividend yield over the coming year plus investors' long-term growth expectations. Because the dividend yield is a key component in applying the DCF model, its usefulness is hampered for firms that do not pay common dividends. Accordingly, my DCF analysis of the market rate of return properly focused on the dividend paying firms included in the S&P 500.

Meanwhile, Mr. Baudino (p. 28) predicated his DCF analysis of the market rate of return on the companies followed by Value Line. Of these approximately 1,700 companies, over 750 do not pay common dividends. In other words, close to one-half of the companies that underpin Mr. Baudino's DCF analysis do not have the data necessary to implement this approach. Further, many of these firms are relatively small and lack a meaningful operating history. As a result, there is also greater uncertainty associated with estimating the future growth expectations that are central to the application of the DCF method. Taken together, these factors impugn the reliability of Mr. Baudino's market risk premium and confirm my decision to restrict my analysis to the established, dividend paying firms in the S&P 500.

Q. WHAT OTHER PROBLEMS ARE ASSOCIATED WITH MR. BAUDINO'S MARKET RATE OF RETURN BASED ON VALUE LINE DATA?

A. As detailed in my direct testimony and explained earlier here, expected growth in earnings is far more likely to be representative of investors' forward-looking expectations. As Mr. Baudino noted, "[I]t is not surprising that earnings and cash flow are considered more important than book value and dividends, particularly for non-utility companies that may not pay out much in the way of dividends."[75] But despite this admission and the fact that over one-half of the companies underlying his CAPM analysis do not even pay common dividends, Mr. Baudino nevertheless included dividend and book value growth rates in the DCF analysis he employed to estimate the expected market rate of return. This had the effect of understating the resulting CAPM cost of equity estimates.

VII. FLOTATION COSTS SHOULD BE CONSIDERED

Q. PLEASE RESPOND TO THE ARGUMENT THAT THERE IS NO BASIS TO CONSIDER THE IMPACT OF FLOTATION COSTS IN ESTABLISHING THE COMPANIES' ROE.

A. The need for a flotation cost adjustment to compensate for past equity issues has been recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must

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[75] Baudino Direct at 39.

consider total equity, including retained earnings.[76] Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

> Another controversy is whether the underpricing allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. ... The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[77]

Q. CAN YOU PROVIDE A SIMPLE NUMERICAL EXAMPLE ILLUSTRATING WHY A FLOTATION COST ADJUSTMENT IS NECESSARY TO ACCOUNT FOR PAST FLOTATION COSTS?

A. Yes. The following example demonstrates that investors will not have the opportunity to earn their required rate of return (*i.e.*, dividend yield plus expected growth) unless an allowance for past flotation costs is included in the allowed rate of return on equity. Assume a utility sells $10 worth of common stock at the beginning of year 1. If the utility incurs flotation costs of $0.48 (5 percent of the net proceeds), then only $9.52 is available to invest in rate base. Assume that common shareholders' required rate of return is 11.5 percent, the expected dividend in year 1 is $0.50 (*i.e.*, a dividend yield of 5 percent), and that growth is expected to be 6.5 percent annually. As developed below, if the allowed rate of return on common

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[76] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly,* May, 2, 1985.

[77] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports* at 175 (1994).

equity is only equal to the utility's 11.5 percent "bare bones" cost of equity, common stockholders will not earn their required rate of return on their $10 investment, since growth will really only be 6.25 percent, instead of 6.5 percent:

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$ 10.00	1.050	11.50%	$ 1.09	$ 0.50	45.7%
2	$ 9.52	$ 0.59	$ 10.11	$ 10.62	1.050	11.50%	$ 1.16	$ 0.53	45.7%
3	$ 9.52	$ 0.63	$ 10.75	$ 11.29	1.050	11.50%	$ 1.24	$ 0.56	45.7%
Growth			**6.25%**	**6.25%**			**6.25%**	**6.25%**	

The reason that investors never really earn 11.5 percent on their investment in the above example is that the $0.48 in flotation costs initially incurred to raise the common stock is not treated like debt issuance costs (*i.e.*, amortized into interest expense and therefore increasing the embedded cost of debt), nor is it included as an asset in rate base.

Q. CAN YOU ILLUSTRATE HOW THE FLOTATION COST ADJUSTMENT ALLOWS INVESTORS TO BE FULLY COMPENSATED FOR THE IMPACT OF PAST ISSUANCE COSTS?

A. Yes. As discussed in my direct testimony, one method for calculating the flotation cost adjustment is to multiply the dividend yield by a flotation cost percentage. Thus, with a 5 percent dividend yield and a 5 percent flotation cost percentage, the flotation cost adjustment in the above example would be approximately 25 basis points. As shown below, by allowing a rate of return on common equity of 11.75 percent (an 11.5 percent cost of equity plus a 25 basis point flotation cost adjustment), investors earn their 11.5 percent required rate of return, since actual growth is now equal to 6.5 percent:

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$ 10.00	1.050	11.75%	$ 1.12	$ 0.50	44.7%
2	$ 9.52	$ 0.62	$ 10.14	$ 10.65	1.050	11.75%	$ 1.19	$ 0.53	44.7%
3	$ 9.52	$ 0.66	$ 10.80	$ 11.34	1.050	11.75%	$ 1.27	$ 0.57	44.7%
Growth			**6.50%**	**6.50%**			**6.50%**	**6.50%**	

The only way for investors to be fully compensated for issuance costs is to include an ongoing adjustment to account for past flotation costs when setting the return on common equity. This is the case regardless of whether or not the utility is expected to issue additional shares of common stock in the future.

Q. PLEASE RESPOND TO DR. WOOLRIDGE'S SPECIFIC CRITICISMS OF YOUR FLOTATION COST ADJUSTMENT.

A. First, while Dr. Woolridge suggests that flotation costs should be ignored because my adjustment was not predicated on a precise accounting for LGE, this belies the point of the adjustment. As discussed in my direct testimony, in contrast to debt issuance costs, which are specifically accounted for on the books of the utility, there is no comparable method for equity flotation costs. The approach outlined in my direct testimony is supported by recognized regulatory textbooks and based on research reported in the academic literature, and the lack of a precise accounting of LGE's past issuance expenses provides no basis to ignore a flotation cost adjustment.

Meanwhile, Dr. Woolridge mistakenly claims that a flotation cost adjustment "is necessary to prevent dilution of the existing shareholders."[78] In fact, a flotation cost adjustment is required in order to allow the utility the opportunity to recover the issuance costs associated with selling common stock. Dr. Woolridge's observation about the level of market-to-book ratios may be factually correct, but it has nothing

[78] Woolridge Direct at 75.

to do with flotation costs. The fact that market prices may be above book value does not alter the fact that a portion of the capital contributed by equity investors is not available to earn a return because it is paid out as flotation costs. Even if the utility is not expected to issue additional common stock, a flotation cost adjustment is necessary to compensate for flotation costs incurred in connection with past issues of common stock.

Dr. Woolridge's argument (p. 71) that flotation costs are "not out-of-pocket expenses" is simply wrong. Dr. Woolridge apparently believes that if investors in past common stock issues had paid the full issuance price directly to the utility and the utility had then paid underwriters' fees by issuing a check to its investment bankers, that flotation cost would be a legitimate expense. Dr. Woolridge's observation merely highlights the absence of an accounting convention to properly accumulate and recover these legitimate and necessary costs.

With respect to Dr. Woolridge's (p. 71) and Mr. Baudino's (p. 43) contention that flotation costs are somehow accounted for in current stock prices,[79] *Regulatory Finance: Utilities' Cost of Capital* has this to say:

> A third controversy centers around the argument that the omission of flotation cost is justified on the grounds that, in an efficient market, the stock price already reflects any accretion or dilution resulting from new issuances of securities and that a flotation cost adjustment results in a double counting effect. The simple fact of the matter is that whatever stock price is set by the market, the company issuing stock will always net an amount less than the stock price due to the presence of intermediation and flotation costs. As a result, the company must earn slightly more on its reduced rate base in order to produce a return equal to that required by shareholders.[80]

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[79] Woolridge Direct at 75:20-23.

[80] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 174 (1994).

Similarly, the need to consider past flotation costs has been recognized in the financial literature, including sources that Dr. Woolridge relied on in his testimony. Specifically, Ibbotson Associates concluded that:

> Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital).[81]

VIII. PROXY GROUP REVENUE TEST IS UNSUPPORTED

Q. DO YOU AGREE WITH DR. WOOLRIDGE AND MR. BAUDINO THAT THE SOURCE OF A UTILITY'S REVENUES IS A VALID CRITERION IN SELECTING A PROXY GROUP FOR LGE?

A. No. Mr. Baudino selected proxy companies with at least 50 percent of their revenues from electric operations,[82] while Dr. Woolridge argued for the elimination of companies from his electric proxy group if less that 80 percent of total revenues were attributable to electric utility service.[83] However, both witnesses failed to demonstrate how their arbitrary criteria translate into differences in the investment risks perceived by investors. Any comparison of objective indicators demonstrates that the 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 the approach adopted by Mr. Baudino and Dr. Woolridge that justify rejecting their proposed proxy group criteria.

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[81] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2006 Yearbook*, at 35. In addition, the July 19, 2007 decision of the Maryland Public Service Commission in Case No. 9093 cited by Dr. Woolridge (p. 55) approved an adjustment for flotation costs.

[82] Baudino Direct at 17.

[83] Woolridge Direct at 12. Dr. Woolridge applied a 50 percent threshold in determining his gas proxy group.

Q. DID DR. WOOLRIDGE OR MR. BAUDINO DEMONSTRATE A NEXUS BETWEEN THEIR REVENUE CRITERIA AND OBJECTIVE MEASURES OF INVESTMENT RISK?

A. No. Under the regulatory standards established by *Bluefield*[84] and *Hope*,[85] 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 and Mr. Baudino presented no evidence to demonstrate a relationship between the arbitrary criteria that they employed and the views of real-world investors in the capital markets.

Moreover, the comfort that Dr. Woolridge and Mr. Baudino take in limiting his proxy groups is misplaced. Due to differences in business segment definition and reporting among utilities, it is often difficult for investors to accurately apportion financial measures, such as total revenues, between utility segments (*e.g.*, electric and natural gas) or regulated and non-regulated sources. 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.[86]

Similarly, FERC has specifically rejected arguments a utility "should be excluded from the proxy group given the risk factors associated with its unregulated, non-utility business operations."[87]

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[84] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923).
[85] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[86] *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 at P 118 (2008).
[87] *Bangor Hydro-Elec. Co.*, 117 FERC ¶ 61,129 at PP 19, 26 (2006).

Q. DO OBJECTIVE CRITERIA CONFIRM THE CONCLUSION THAT DR. WOOLRIDGE'S AND MR. BAUDINO'S ARBITRARY REVENUE TESTS DO NOT REFLECT COMPARABLE RISK IN THE MINDS OF INVESTORS?

A. Yes. Credit 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 credit rating agencies are primarily focused on the risk of default associated with the firm's debt securities, credit 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).[88]

Indeed, Dr. Woolridge and Mr. Baudino apparently agree. Both reviewed the bond ratings of the companies in their alternative proxy groups and Mr. Baudino testified (p. 14) that bond ratings are based on "detailed analyses of factors that contribute to the risks of a particular investment" and "quantify the total risk of a company."

All of the utilities followed by Value Line identified as having electric revenues less than Mr. Baudino's 50 percent cutoff have bond ratings equal to or stronger than the criterion used to establish his proxy group.

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[88] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utility Reports* at 81 (1994).

Q. WHAT DO YOU CONCLUDE FROM THIS REVIEW OF INDEPENDENT, OBJECTIVE RISK FACTORS USED BY THE INVESTMENT COMMUNITY?

A. Considering that credit ratings provide one of the most widely accepted benchmarks for investment risks, a comparison of this objective indicator demonstrates that the range of risks for the companies eliminated under the arbitrary revenue criterion proposed by Mr. Baudino are either less risky than or comparable to those of the other firms in my Utility Proxy Group. Contrary to the assertions of Mr. Baudino,[89] comparisons of this objective, published indicator that incorporates consideration of a broad spectrum of risks confirms that there is no link between the 50 percent electric revenue test he applied to define his proxy group and the risk perceptions of investors. In other words, there is no basis to distinguish between the risks that investors associate with the companies that Mr. Baudino would eliminate under his revenue criterion and those included in his proxy group.

Q. ARE THERE INCONSISTENCIES AND ERRORS ASSOCIATED WITH THE REVENUE TEST PROPOSED BY MR. BAUDINO?

A. Yes. While Mr. Baudino 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 revenue impact of gas utility operations. For example, despite the fact that SCANA Corporation reported in its 2009 Form 10-K report that electric and gas utility operations contributed 73 percent of consolidated revenues, Mr. Baudino would exclude this firm under his revenue test. Similarly, while Mr. Baudino's source reports that CenterPoint Energy, Inc.'s electric utility operations contributed only 19 percent of total revenues, the electric and gas utility segments

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[89] *See, e.g,* Case No. 2009-00459, Response to KPCo 1-9.

posted 2009 revenues equal to 65.1 percent of the total consolidated revenues. Meanwhile, Wisconsin Energy Corporation reported in its 2009 Form 10-K Report (p. 109) that its regulated utility segment accounted for approximately 99.7 percent of total revenues. Considering the similarities in the regulatory and business environments for regulated electric and gas utility operations, and the fact that LGE operates in both segments, the failure of Mr. Baudino to incorporate gas utility revenues in implementing his test is inappropriate.

The arbitrary nature of the 50 percent revenue criterion proposed by Mr. Baudino is further illustrated by the lack of any independent, objective findings to support his imposed threshold. Apart from the absence of any evidence to link revenues with investors' risk perceptions, Mr. Baudino granted that there is no underlying basis for his arbitrary test.[90]

The subjective nature of the revenue criteria proposed by Mr. Baudino and Dr. Woolridge is further illustrated by the wide disparity between the thresholds imposed by these respective witnesses. Apart from the absence of any objective evidence to link revenues with investors' risk perceptions, the fact that one witness would impose a 80 percent electric revenue criterion (Dr. Woolridge) while the other would set the bar at 50 percent (Mr. Baudino) reveals the lack of any underlying basis for their tests.

In fact, Dr. Woolridge cannot seem to decide for himself what the correct cutoff should be. For example, in his November 2008 testimony in Case No. 080317-EI before the FPSC involving Tampa Electric Company, Dr. Woolridge

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[90] Response to KPSC 1-11. In addition, as indicated in response to data request KPCo 1-9 (b) in Case No. 2009-00459, "Mr. Baudino did not prepare any studies or documentation for the 50% regulated electric revenue criterion." Mr. Baudino granted in response to KPCo 1-9 (c) that he had no analyses, studies, or publications to support his position that the percent of revenues from electric utility operations is related to investors' risk perceptions.

argued to exclude companies with less than 75 percent of revenues attributable to electric operations. Similarly, Dr. Wooridge's artificial revenue threshold for his electric utility group here is inconsistent with his findings for his gas proxy group, where he used a 50 percent revenue threshold from regulated gas operations. If Dr. Woolridge finds it acceptable for certain gas utilities to have less than 80 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 80 percent revenue threshold imposed on his electric proxy 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 PROBLEMS ASSOCIATED WITH THE DATA USED BY DR. WOOLRIDGE AND MR. BAUDINO TO SCREEN HIS PROXY GROUP?

A. Yes. These witnesses applied their credit rating screen based on bond ratings reported by AUS Utility Reports. However, these reflect senior debt ratings, not the corporate, or issuer, credit rating for the utility as a whole. Because equity investors are focused on the overall investment risks of the firm, and not those attributable to a specific debt issue, the appropriate measure is the corporate credit rating.

For example, while Dr. Woolridge included UniSource Energy Corporation ("UniSource") in his electric proxy group based on a reported S&P bond rating of "BBB+", the corporate credit rating corresponding to UniSource is "BB+".[91] This rating falls below the ladder of investment grade ratings and places UniSource in the

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[91] Standard & Poor's Corporation, "Tucson Electric Power Co.," *RatingsDirect* (Dec. 22, 2009). S&P's ratings, including those relied on by Mr. Baudino, reflect its assessment of UniSource's primary subsidiary.

same category as speculative, or "junk" investments. As S&P informed investors, UniSource's finances and risks reflect "the continuing effect of a series of losses and near bankruptcy two decades ago."[92] Similarly, prior to requesting that S&P withdraw its ratings in December 2009,[93] Central Vermont Public Service Corporation, which was included in Dr. Woolridge's electric proxy group, was also assigned a corporate credit rating of "BB+". These junk bond ratings do not reflect comparable risks to LGE and the financial and operating challenges that typically accompany a speculative grade rating skew the data used to estimate the cost of equity and seriously compromise the resulting DCF estimates.

Q. ARE THERE OTHER MANIFESTATIONS OF THIS PROBLEM REFLECTED IN THE TESTIMONY OF MR. BAUDINO AND DR. WOOLRIDGE?

A. Yes. As noted above, 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 and non-utility sources based on the financial information available to investors. Consider the example of Dominion Resources, Inc. (Dominion), which Mr. Baudino and Dr. Woolridge excluded from their sample groups based on the contention that only 43 percent of Dominion's revenues were from electric utility sources. This 43 percent figure used to apply Mr. Baudino's electric revenue criterion is unrelated to the actual percentage of regulated revenues for Dominion, which classifies its operations into three primary segments – Dominion Virginia Power, Dominion Energy, and Dominion Generation.

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[92] *Id.*

[93] Standard & Poor's Corporation, "Research Update: Central Vermont Public Service Corp. Ratings Withdrawn At The Company's Request," *RatingsDirect* (Dec. 10, 2009).

Dominion Virginia Power includes regulated electric distribution and transmission, as well as non-regulated retail energy marketing operations. Similarly, Dominion Energy includes the regulated natural gas distribution business, as well as tariff-based natural gas pipeline and natural gas storage businesses subject to varying degrees of rate regulation, LNG import and storage activities, and petroleum exploration and production. Meanwhile, Dominion Generation includes the generation operations for both the electric utility and merchant power generation operations. As a result, even ignoring the fact that there is no clear link between the source of a utility's revenues and investors' risk perceptions, it is not possible to accurately apply Mr. Baudino's criterion.

IX. NO ROE ADJUSTMENT IS WARRANTED FOR RATE DESIGN

Q. WHAT ROE DOES DR. WOOLRIDGE RECOMMEND IF LGE'S PROPOSED RATE DESIGN IS APPROVED?

A. Based on the findings in seven other regulatory proceedings, Dr. Woolridge suggests that the KPSC should make a downward adjustment to LGE's ROE if the Company's straight fixed variable ("SFV") rate design proposals are approved. Dr. Woolridge recommends that the KPSC consider the "potential" risk reduction associated with the requested rate design, along with, "the adjustments made by other commission for rate design mechanisms."[94] While Dr. Woolridge made no specific recommendation concerning the magnitude of such an adjustment, he suggested that, "an adjustment of up to 50 basis points may be appropriate."[95]

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[94] Woolridge Direct at 54.
[95] *Id.* at 53.

Q. WHAT IS THE EFFECT OF LGE'S PROPOSED RATE DESIGN FROM INVESTORS' PERSPECTIVE?

A. Rate design initiatives and other forms of revenue decoupling address the investment community's heightened concerns over the risks associated with declining consumption by helping to preserve a utility's opportunity to collect the level of revenues it was authorized when rates were established. Because utility revenues and cash flow typically depend on sales volume, a utility will be unable to recover its fixed costs on a timely basis, if at all, to the degree that usage is declining. Regulatory initiatives, such as LGE's rate design proposals, help to lessen the negative implications of declining usage for the utility's financial integrity and credit standing.

Meanwhile, the revenue losses due to declining use per customer addressed by LGE's proposed rate design are only those that occur between rate cases. Use per customer is essentially "reset" in each rate case, so that the loss of revenues and cash flows due to declining use per customer can also be ameliorated by more frequent rate cases or other common ratemaking techniques (*e.g.*, future test years and recognizing known and measurable changes). As a result, the benefit of rate design initiatives and other forms of decoupling with respect to declining customer usage is that they reduce regulatory lag, with its value depending on the frequency that the utility would otherwise file rate cases to address other expense, investment, and revenue issues.

Q. IS THERE ANY MERIT TO DR. WOOLRIDGE'S PROPOSAL TO REDUCE LGE'S ALLOWED ROE IF ITS PROPOSED RATE DESIGN IS APPROVED?

A. No. Adopting LGE's proposed rate design would be supportive of its financial integrity, but it would not constitute a dramatic change in the investment risk that investors associate with the Company. Moreover, gas utilities across the U.S. are increasingly availing themselves of similar adjustments. There is certainly no evidence to suggest that implementation of the proposed rate design alone would alter the relative risk of LGE enough to warrant a change in its required ROE.

Q. WOULD APPROVAL OF LGE'S PROPOSED RATE DESIGN IMPLY THAT ITS INVESTMENT RISKS ARE LOWER THAN FOR THE COMPANIES IN THE PROXY GROUPS USED TO ESTIMATE THE COST OF EQUITY?

A. No. Adjustment clauses and cost trackers, along with rate design measures and other mechanisms designed to decouple a utility's revenues from customer usage, have been increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity of investors to uncertainty over fluctuations in costs and regulatory lag, and in light of the importance of advancing other public interest goals such as energy conservation, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interest of utilities and their customers in favor of reducing consumption through decoupling and other adjustment mechanisms. Energy conservation and efficiency may be desirable, but as S&P noted, "policy objectives can sometimes increase utilities' uncertainty and credit risk."[96] S&P went on to conclude that, "efficiency programs that lack decoupling may carry a higher level of credit risk."[97] More recently, Fitch observed:

> An emerging regulatory trend for integrated electric utilities is the initiation of electricity revenue decoupling in response to the recent

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[96] Standard & Poor's Corporation, "When Energy Efficiency Means Lower Electric Bills, How Do Utilities Cope?," *RatingsDirect* (Mar. 9, 2009).
[97] *Id.*

> softness of demand and state policies that include ambitious energy-efficiency targets.[98]

While not always directly analogous to the specific rate design provisions proposed by LGE, the objective is similar; namely, to allow the utility an opportunity to earn a fair rate of return and mitigate exposure to attrition in an era of rising costs and declining consumption.

Reflective of this industry trend, the companies in the proxy groups referenced by Dr. Woolridge and in my direct testimony operate under a variety of rate design and adjustment mechanisms ranging from weather normalization, riders to recover bad debt expense and post-retirement employee benefit costs, to revenue decoupling and adjustment clauses designed to address the rising costs of environmental compliance measures. As shown in Table WEA-9, Dr. Woolridge has recognized in another case that all of the utilities in his gas proxy group operate under mechanisms that reduce exposure to revenue fluctuations, whether in the form of weather normalization ("WNA"), rate design provisions, or revenue decoupling:

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[98] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010," *Global Power North America Special Report* (Dec. 4, 2009). Fitch observed that electric revenue decoupling had been initiated or was allowed in California, Ohio, Vermont, New York, and Maryland, with pilot programs in Wisconsin and Idaho, while 18 states have approved the implementation of revenue decoupling for gas utilities.

TABLE WEA-9
ADJUSTMENT MECHANISMS – WOOLRIDGE PROXY GROUP

Gas Proxy Group

Company	PGA	WNA	SFV	Decoupling
AGL Resources Inc. (NYSE-ATG)	x	x	x-GA,VA	
Atmos Energy Corporation (NYSE-ATO)	x	x		
Laclede Group, Inc. (NYSE-LG)	x	x		
NICOR Inc. (NYSE-GAS)	x	x		
Northwest Natural Gas Co. (NYSE-NWN)	x	x		x-OR
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	x	x-SC,TN		x-NC
South Jersey Industries, Inc. (NYSE-SJI)	x	x		x-NJ
Southwest Gas Corporation (NYSE-SWX)	x			x-CA
WGL Holdings, Inc. (NYSE-WGL)	x	x		x-MD
Mean				

Data Source: Company 10-K reports

Source: Nebraska Public Service Commission, Docket No. NG-0061, Response to Information Request No. BE-48.

Similarly, Fitch observed that electric revenue decoupling had been initiated or was allowed in California, Ohio, Vermont, New York, and Maryland, with pilot programs in Wisconsin and Idaho, while 18 states have approved the implementation of revenue decoupling for gas utilities.[99]

Q. **IS THERE A DOWNSIDE TO RATE DESIGN PROVISIONS AND OTHER MECHANISMS THAT DECOUPLE REVENUES FROM SALES VOLUMES?**

A. Yes. The investment community does not view mechanisms to address revenue stabilization, such as weather mitigants or rate design mechanisms that shift away from volumetric recovery of fixed costs, as entirely positive. This is because, while such measures dampen the volatility of a utility's revenues, they also largely preclude the prospects of greater earnings due to higher consumption. This double-edged sword was noted by S&P in the context of weather adjustment clauses:

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[99] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010," *Global Power North America Special Report* (Dec. 4, 2009).

> Some LDCs are reluctant to pursue such provisions, because they don't want to forego the upside earnings potential of a significantly colder-than-normal winter.[100]

Similarly, Moody's warned that "it is unclear, at this time, as to whether these cost riders/trackers may prove to have hidden consequences over the long-term horizon."[101] Thus, investors would also consider the loss of upside potential in evaluating the impact of rate design and other decoupling mechanisms.

Q. WHAT DOES THIS IMPLY WITH RESPECT TO EVALUATING A FAIR ROE FOR LGE?

A. While the rate design provision proposed by LGE would be supportive of its financial integrity and credit ratings, there is certainly no evidence to suggest that these provisions would justify any downward adjustment to the ROE range.

As explained above, utilities across the U.S. that LGE competes with for new capital – including those in the proxy groups used to estimate the cost of equity in this proceeding – are increasingly availing themselves of similar adjustments. Similarly, the firms in the Non-Utility Proxy Group also have the ability to alter prices in response to rising production costs, with the added flexibility to withdraw from the market altogether. As a result, the impact of utilities' ability to mitigate the risk of declining revenues and cash flows is already reflected in the cost of equity estimates developed by Dr. Woolridge and in my direct testimony, and no separate adjustment to LGE's ROE is necessary or warranted. While the rate design proposed by LGE would help to partially attenuate exposure to declining revenues, this leveling of the playing field only serves to address factors that could otherwise impair LGE's opportunity to collect its authorized revenues.

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[100] Standard & Poor's Corporation, "Natural Gas Distribution," *Industry Surveys* at 18 (Nov. 29, 2001).

[101] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (January 2009).

Q. DOES DR. WOOLRIDGES'S REFERENCE TO SELECTED REGULATORY ORDERS (P. 54) PROVIDE A SOUND BASIS FOR ANY ROE ADJUSTMENT IN THIS CASE?

A. Certainly not. Dr. Woolridge's conclusions were not based on a comprehensive review of rate case orders; rather, he simply selected a handful of decisions that seemed to support his position, while ignoring others that did not. For example, while Dr. Woolridge refers to a decision of the Missouri Public Service Commission ("MPSC") involving Missouri Gas Energy, he ignores other decisions by this agency that run contrary to his views. The MPSC explicitly rejected a proposed downward adjustment to the ROE of Atmos Energy Corporation associated with a fixed delivery charge rate design, concluding in its 2007 order that:

> [Public Counsel's witness] "did not analyze the cost of common equity of companies that may have similar risk characteristics as those that may be in effect for Atmos' Missouri operations" and "did not even recognize that many of [Staff's] . . . comparable companies have weather mitigation rate designs that minimize risks related to changes in the weather." ... [C]ontrary to the criticism that Staff's analysis does not consider the decreased business risk associated with its proposed rate design, seven of the eight companies that Mr. Barnes identified as comparable to Atmos operate under some type of revenue stabilization mechanisms for their residential and small commercial customers. In addition, Mr. Barnes confirmed that there was no need for further reduction in his recommended ROE because risk is already reflected in his comparable group analysis. The evidence also revealed that Atlanta Gas and Light, one of the comparable companies, has a rate design similar to what Staff is proposing in this case. That company has been authorized a 10.9 percent return on equity.[102]

Similarly, FERC also recently rejected a proposed downward ROE adjustment based on the claims of the California Public Utilities Commission that tracking and

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[102] *Report and Order*, Case. No. GR-2006-0387 (2007)

decoupling mechanisms reduce risk for utilities under its jurisdiction. As FERC concluded:

> The CPUC also contends that California laws and CPUC's own actions have lowered SoCal Edison's risks. The CPUC comments that in California over 50 percent of the energy revenue requirements are protected by balancing account recovery, but that in this proceeding, there is no evidence to support the position that any of the companies in the WECC or SoCal Edison's proxy group have this same amount of balancing account protection. … [T]hese risk factors are not applicable when determining the base ROE. As we explained herein, when establishing a base ROE for SoCal Edison, we utilize the DCF methodology, and apply a significant set of screening factors. As a result of this process, we have developed a reasonable proxy group that has been sufficiently screened for risk.[103]

As discussed above, there is every indication that any impact of the proposed rate design is already captured in the cost of equity estimates for the proxy group companies, which benefit from a wide variety of adjustment mechanisms. Second, Dr. Woolridge presented no evidence to support any downward adjustment to the ROE, let alone a decrease of up to 50 basis points. With the current yield spread between single-A and triple-B utility bonds amounting to approximately 40 basis points,[104] Dr. Woolridge is suggesting that approval of LGE's proposed rate design would result in a decrease in the cost of equity equivalent to an upgrade spanning an entire rung on the ratings ladder. Of course, there is no indication from the investment community that approval of the proposed rate design would warrant such a pronounced reevaluation of LGE's risks. Third, because Dr. Woolridge's gas proxy group contains A-rated utilities and already has less investment risk than LGE, the results of his analyses already reflect a downward bias attributable to differences in bond ratings and any additional adjustment would be a "double-dip".

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[103] *Southern California Edison Co.*, 131 FERC ¶ 61,020 at PP 61 & 67 (2010).

[104] Based on average yields for March 2010 reported by Moody's Investors Service at www.credittrends.com.

Consequently, Dr. Woolridge's proposed adjustment is entirely divorced from the perceptions of real-world investors and should be ignored.

Q. IS THERE ANY BASIS FOR MS. BROCKWAY'S ASSERTION THAT ASPECTS OF LGE'S PROPOSED RATE DESIGN WARRANT A LOWER ROE?

A. No. While Ms. Brockway asserted that LGE's proposed electric and gas rate design "should be matched be a significant reduction in the allowed return on equity,"[105] she provided no support whatsoever for her recommendation. As indicated in my direct testimony (pp. 60-62) and earlier in response to Dr. Woolridge, there is no support for Ms. Brockway's conclusion that approval of LGE's proposed rate design would fundamentally alter LGE's investment risks relative to the proxy groups used to estimate the cost of equity. Because the utilities in these groups already operate under a wide variety of adjustment mechanisms and rate design initiatives to better ensure that the utility has the opportunity to collect its authorized revenues and recover its costs, any impact of LGE's proposed rate design is already reflected in the resulting cost of equity estimates.

X. THE COMPANY'S CAPITAL STRUCTURE SHOULD BE APPROVED

Q. WHAT WAS DR. WOOLRIDGE'S RATIONALE FOR REJECTING THE CAPITALIZATION REQUESTED BY LGE?

A. Dr. Woolridge's assertion that LGE's capital structure should be rejected was based solely on his conclusion that the equity ratio implied by the Company's capitalization is higher than the average for his electric proxy group.[106]

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[105] Brockway Direct at 13 & 21.

[106] Woolridge Direct at 14.

Q. DOES THIS PROVIDE A LOGICAL BASIS TO REJECT LGE'S ACTUAL CAPITALIZATION?

A. No. As noted in my direct testimony, while industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. While the degree of debt leverage is one consideration impacting investors' risk perceptions, it is not the whole picture. Overall investment risk, such as that reflected in bond ratings and other risk measures referenced by investors, also consider the specific business risks underlying a utility's operations. LGE's credit ratings, which Dr. Woolridge relied on to establish his proxy group, already reflect the combined impact of these business and financial risk exposures. Moreover, LGE's equity ratio falls within the range of capitalizations maintained by the firms in the proxy groups that Dr. Woolridge and I relied on to estimate the cost or equity.

As discussed in my direct testimony, investors and bond rating agencies are increasingly focused on the importance of regulatory support. Making unwarranted adjustments to the capital structure or adopting an unreasonably low ROE would undoubtedly have a negative impact on investors' risk perceptions, and doing both would be outright alarming. Dr. Woolridge's proposed hypothetical capital structure amounts to nothing more than an ill disguised attempt to engineer a lower overall rate of return by substituting debt for equity.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, **William E. Avera**, being duly sworn, deposes and says 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 25th day of May 2010.

LENA PHAN
Notary Public
STATE OF TEXAS
My Comm. Exp. Sept. 18, 2010

(SEAL)
Notary Public

My Commission Expires:

September 18, 2010

VISED DCF ANALYSIS

UDINO PROXY GROUP

	(a)	Growth Rates (b)			Cost of Equity Estimates (c)		
	Dividend	Value		First Call/	Value		First Call/
Company	Yield	Line	Zacks	Thomson	Line	Zacks	Thomson
ALLETE, Inc.	5.4%	-0.5%	3.7%	5.3%	4.9%	9.1%	10.8%
Alliant Energy Corp.	5.2%	7.0%	4.0%	5.6%	12.3%	9.3%	10.9%
Con. Edison, Inc.	5.5%	2.5%	3.0%	3.3%	8.1%	8.6%	8.9%
DTE Energy Company	5.1%	7.0%	5.0%	5.0%	12.3%	10.3%	10.3%
Edison International	3.7%	3.5%	5.0%	2.0%	7.3%	8.8%	5.8%
Entergy Corporation	3.8%	5.0%	4.0%	6.7%	8.9%	7.9%	10.6%
Exelon Corporation	4.5%	1.5%	0.5%	0.0%	6.0%	5.0%	4.4%
IDACORP, Inc.	3.9%	4.5%	5.0%	5.0%	8.4%	9.0%	9.0%
Northeast Utilities	3.9%	7.0%	7.9%	7.8%	11.0%	12.0%	11.9%
Pepco Holdings, Inc.	6.7%	0.5%	5.3%	5.3%	7.2%	12.2%	12.2%
PG&E Corporation	4.0%	6.5%	7.7%	7.0%	10.6%	11.8%	11.1%
Progress Energy Inc.	6.4%	4.5%	4.0%	3.7%	11.0%	10.5%	10.2%
PS Enterprise Group	4.3%	7.5%	1.0%	2.2%	12.0%	5.3%	6.5%
Southern Company	5.4%	4.5%	7.4%	5.1%	10.0%	13.0%	10.6%
Wisconsin Energy Corp.	3.0%	8.0%	8.7%	9.5%	11.1%	11.8%	12.7%
Xcel Energy Inc.	4.8%	6.5%	5.7%	6.2%	11.5%	10.6%	11.1%
Average (d)					**10.6%**	**10.5%**	**10.8%**
						10.6%	

Exhibit (RAB-3).
Exhibit (RAB-4).
Sum of dividend yield and respective growth rate.
Excludes highlighted values.

REVISED DCF ANALYSIS

WOOLRIDGE ELECTRIC PROXY GROUP

		(a)	Growth Rates (b)				Cost of Equity Estimates (c)			
		Dividend	Value	First			Value	First		
	Company	Yield	Line	Call	Zacks	Reuters	Line	Call	Zacks	Reuters
1	ALLETE, Inc.	5.4%	-0.5%	5.3%	3.7%	6.5%	$\boxed{4.8\%}$	10.8%	9.2%	12.0%
2	American Electric Power Co.	5.0%	3.0%	4.0%	3.6%	4.7%	8.1%	9.1%	8.7%	9.8%
3	Central Vermont PS Corp.	4.6%	3.0%	8.9%	N/A	N/A	$\boxed{7.7\%}$	13.7%	N/A	N/A
4	Cleco Corporation	3.6%	8.0%	4.0%	9.0%	4.0%	11.7%	$\boxed{7.7\%}$	12.8%	$\boxed{7.7\%}$
5	DPL Inc.	4.4%	6.5%	4.5%	5.0%	11.7%	11.1%	9.0%	9.5%	16.4%
6	Edison International	3.7%	3.5%	2.0%	5.0%	3.0%	$\boxed{7.2\%}$	$\boxed{5.7\%}$	8.7%	$\boxed{6.7\%}$
7	Empire District Electric Co.	7.1%	7.0%	6.0%	N/A	N/A	14.3%	13.3%	N/A	N/A
8	FirstEnergy Corporation	5.1%	2.0%	3.3%	3.5%	4.0%	$\boxed{7.1\%}$	8.5%	8.7%	9.2%
9	Hawaiian Electric	6.1%	7.0%	8.8%	8.6%	5.8%	13.4%	15.2%	15.0%	12.1%
10	IDACORP, Inc.	3.9%	4.5%	5.0%	5.0%	5.0%	8.5%	9.0%	9.0%	9.0%
11	Northeast Utilities	3.9%	7.0%	7.8%	7.9%	7.6%	11.0%	11.8%	11.9%	11.6%
12	NSTAR	4.5%	5.5%	5.7%	6.0%	5.4%	10.1%	10.4%	10.6%	10.0%
13	Pinnacle West Capital Corp.	6.0%	3.0%	7.0%	7.0%	6.5%	9.1%	13.2%	13.2%	12.7%
14	PPL Corporation	4.5%	5.0%	11.0%	11.4%	8.6%	9.7%	15.7%	16.2%	13.4%
15	Portland General Electric	5.2%	3.5%	6.0%	5.8%	7.0%	8.8%	11.4%	11.2%	12.4%
16	Progress Energy Inc.	6.4%	4.5%	3.7%	4.0%	3.9%	11.1%	10.3%	10.6%	10.4%
17	Southern Company	5.3%	4.5%	4.8%	7.1%	4.9%	9.9%	10.2%	12.6%	10.3%
18	UIL Holdings Corp.	6.3%	3.0%	4.4%	4.0%	4.1%	9.3%	10.8%	10.4%	10.5%
19	UniSource Energy	3.9%	17.0%	5.0%	5.0%	N/A	$\boxed{21.2\%}$	9.0%	9.0%	N/A
20	Xcel Energy Inc.	4.9%	6.5%	6.1%	5.7%	6.1%	11.5%	11.1%	10.7%	11.2%
	Average (d)						**10.5%**	**11.2%**	**11.0%**	**11.4%**

11.0%

(a) Exhibit JRW-10, p. 2.
(b) Exhibit JRW-10, p. 3.
(c) Sum of dividend yield and respective growth rate.
(d) Excludes highlighted values.

REVISED DCF ANALYSIS

WOOLRIDGE GAS PROXY GROUP

		(a)	Growth Rates (b)				Cost of Equity Estimates (c)			
		Dividend	Value	First			Value	First		
	Company	Yield	Line	Call	Zacks	Reuters	Line	Call	Zacks	Reuters
1	AGL Resources, Inc.	4.8%	3.5%	5.1%	4.5%	5.6%	8.4%	10.0%	9.4%	10.5%
2	Atmos Energy Corp.	4.7%	4.0%	4.2%	5.0%	4.5%	8.8%	9.0%	9.8%	9.3%
3	Laclede Group	4.8%	3.5%	3.5%	3.0%	N/A	8.3%	8.3%	$\boxed{7.8\%}$	N/A
4	Nicor, Inc.	4.6%	1.5%	4.3%	3.7%	2.4%	$\boxed{6.1\%}$	9.0%	8.4%	$\boxed{7.0\%}$
5	Northwest Natural Gas	3.7%	5.0%	5.5%	5.7%	5.5%	8.8%	9.3%	9.5%	9.3%
6	Piedmont Natural Gas	4.3%	8.0%	7.0%	6.3%	7.0%	12.5%	11.5%	10.7%	11.5%
7	South Jersey Industries	3.4%	5.5%	11.7%	11.6%	13.5%	8.9%	15.2%	15.1%	$\boxed{17.1\%}$
8	Southwest Gas	3.4%	6.0%	3.3%	7.0%	5.5%	9.5%	$\boxed{6.8\%}$	10.6%	9.0%
9	WGL Holdings, Inc.	4.5%	4.0%	0.6%	0.6%	0.6%	8.6%	$\boxed{5.1\%}$	$\boxed{5.1\%}$	$\boxed{5.1\%}$
	Average (d)						**9.2%**	**10.3%**	**10.5%**	**9.9%**
								10.0%		

(a) Exhibit JRW-10, p. 2.
(b) Exhibit JRW-10, pp. 4-5.
(c) Sum of dividend yield and respective growth rate.
(d) Excludes highlighted values.

BAUDINO PROXY GROUP

		(a)	(b)	(c)
	Company	Dividend Yield	Price Growth	Cost of Equity
1	ALLETE, Inc.	5.4%	0.9%	$\boxed{6.3\%}$
2	Alliant Energy Corp.	5.2%	7.6%	13.0%
3	Con. Edison, Inc.	5.5%	3.3%	8.8%
4	DTE Energy Company	5.1%	4.0%	9.3%
5	Edison International	3.7%	8.9%	12.8%
6	Entergy Corporation	3.8%	6.9%	10.8%
7	Exelon Corporation	4.5%	5.7%	10.3%
8	IDACORP, Inc.	3.9%	2.5%	$\boxed{6.4\%}$
9	Northeast Utilities	3.9%	8.2%	12.3%
10	Pepco Holdings, Inc.	6.7%	3.6%	10.4%
11	PG&E Corporation	4.0%	4.2%	8.3%
12	Progress Energy Inc.	6.4%	2.5%	8.9%
13	PS Enterprise Group	4.3%	7.0%	11.5%
14	Southern Company	5.4%	6.2%	11.8%
15	Wisconsin Energy Corp.	3.0%	7.0%	10.1%
16	Xcel Energy Inc.	4.8%	3.3%	8.1%
	Average (d)			**10.5%**

(a) Exhibit (RAB-3).
(b) The Value Line Investment Survey (Feb. 26, Mar. 26, 7 May 7, 2010).
(c) Sum of dividend yield (adjusted for one-half year's growth) and growth rate.
(d) Excludes highlighted values.

DCF PRICE GROWTH

WOOLRIDGE ELECTRIC PROXY GROUP

	Company	(a) Dividend Yield	(b) Price Growth	(c) Cost of Equity
1	ALLETE, Inc.	5.4%	0.9%	$\boxed{6.2\%}$
2	American Electric Power Co.	5.0%	4.3%	9.4%
3	Central Vermont PS Corp.	4.6%	9.0%	13.9%
4	Cleco Corporation	3.6%	2.3%	$\boxed{6.0\%}$
5	DPL Inc.	4.4%	6.6%	11.2%
6	Edison International	3.7%	8.9%	12.8%
7	Empire District Electric Co.	7.1%	6.8%	14.1%
8	FirstEnergy Corporation	5.1%	11.2%	16.6%
9	Hawaiian Electric Industries, Inc.	6.1%	1.0%	$\boxed{7.2\%}$
10	IDACORP, Inc.	3.9%	2.5%	$\boxed{6.4\%}$
11	Northeast Utilities	3.9%	8.2%	12.2%
12	NSTAR	4.5%	6.4%	11.0%
13	Pinnacle West Capital Corp.	6.0%	2.9%	9.0%
14	PPL Corporation	4.5%	7.8%	12.5%
15	Portland General Electric	5.2%	5.2%	10.5%
16	Progress Energy Inc.	6.4%	2.5%	9.0%
17	Southern Company	5.3%	6.2%	11.7%
18	UIL Holdings Corporation	6.3%	2.1%	8.4%
19	UniSource Energy Corporation	3.9%	14.3%	$\boxed{18.5\%}$
20	Xcel Energy Inc.	4.9%	3.3%	8.2%
	Average (d)			**11.4%**

(a) Exhibit JRW-10, p. 2.
(b) The Value Line Investment Survey (Feb. 26, Mar. 26, 7 May 7, 2010).
(c) Sum of dividend yield (adjusted for one-half year's growth) and growth rate.
(d) Excludes highlighted values.

DCF PRICE GROWTH

WOOLRIDGE GAS PROXY GROUP

	Company	(a) Dividend Yield	(b) Price Growth	(c) Cost of Equity
1	AGL Resources, Inc.	4.8%	7.6%	12.6%
2	Atmos Energy Corp.	4.7%	4.8%	9.5%
3	Laclede Group	4.8%	7.4%	12.3%
4	Nicor, Inc.	4.6%	4.4%	9.1%
5	Northwest Natural Gas	3.7%	5.8%	9.7%
6	Piedmont Natural Gas	4.3%	6.1%	10.6%
7	South Jersey Industries	3.4%	3.4%	$\boxed{6.8\%}$
8	Southwest Gas	3.4%	6.6%	10.1%
9	WGL Holdings, Inc.	4.5%	3.8%	8.3%
	Average (d)			**10.3%**

(a) Exhibit JRW-10, p. 2.
(b) The Value Line Investment Survey (Mar. 12, 2010).
(c) Sum of dividend yield (adjusted for one-half year's growth) and growth rate.
(d) Excludes highlighted values.

EXPECTED EARNINGS APPROACH

BAUDINO PROXY GROUP

		(a)	(b)	(c)
			Value Line	
		Expected	Adjustment	Adjusted
	Company	ROE	Factor	ROE
1	ALLETE, Inc.	8.0%	1.0251	8.2%
2	Alliant Energy Corp.	11.5%	1.0261	11.8%
3	Con. Edison, Inc.	9.5%	1.0165	9.7%
4	DTE Energy Company	9.0%	1.0265	9.2%
5	Edison International	9.0%	1.0262	9.2%
6	Entergy Corporation	12.5%	1.0318	12.9%
7	Exelon Corporation	16.0%	1.0322	16.5%
8	IDACORP, Inc.	8.5%	1.0307	8.8%
9	Northeast Utilities	9.0%	1.0274	9.2%
10	Pepco Holdings, Inc.	7.5%	1.0254	7.7%
11	PG&E Corporation	12.0%	1.0386	12.5%
12	Progress Energy Inc.	9.0%	1.0162	9.1%
13	PS Enterprise Group	14.5%	1.0421	15.1%
14	Southern Company	13.0%	1.0321	13.4%
15	Wisconsin Energy Corp.	12.0%	1.0278	12.3%
16	Xcel Energy Inc.	10.0%	1.0290	10.3%
	Average (d)			**11.2%**

(a) Exhibit JRW-10, p. 5.
(b) Adjustment to convert year-end "r" to an average rate of return based on data from The
(c) Value Line Investment Survey (Mar. 12, 2010).
(a) x (b).
(d) Excludes highlighted values.

WOOLRIDGE ELECTRIC PROXY GROUP

		(a)	(b)	(c)
			Value Line	
		Expected	Adjustment	Adjusted
	Company	ROE	Factor	ROE
1	ALLETE, Inc.	8.0%	1.0251	8.2%
2	American Electric Power Co.	10.0%	1.0293	10.3%
3	Central Vermont PS Corp.	6.5%	1.0342	6.7%
4	Cleco Corporation	11.0%	1.0318	11.3%
5	DPL Inc.	28.0%	1.0204	28.6%
6	Edison International	11.0%	1.0262	11.3%
7	Empire District Electric Co.	10.0%	1.0208	10.2%
8	FirstEnergy Corporation	13.0%	1.0284	13.4%
9	Hawaiian Electric Industries, Inc.	10.5%	1.0253	10.8%
10	IDACORP, Inc.	7.5%	1.0306	7.7%
11	Northeast Utilities	9.0%	1.0274	9.2%
12	NSTAR	14.0%	1.0238	14.3%
13	Pinnacle West Capital Corp.	9.0%	1.0348	9.3%
14	PPL Corporation	16.5%	1.0271	16.9%
15	Portland General Electric	8.5%	1.0305	8.8%
16	Progress Energy Inc.	9.0%	1.0162	9.1%
17	Southern Company	13.0%	1.0321	13.4%
18	UIL Holdings Corporation	10.5%	1.0186	10.7%
19	UniSource Energy Corporation	11.0%	1.0286	11.3%
20	Xcel Energy Inc.	10.5%	1.0290	10.8%
	Average (d)			**10.9%**

(a) Exhibit JRW-10, p. 4.
(b) Adjustment to convert year-end "r" to an average rate of return based on data from The Value Line Investment Survey (Mar. 12, 2010).
(c) (a) x (b).
(d) Excludes highlighted values.

EXPECTED EARNINGS APPROACH

WOOLRIDGE GAS PROXY GROUP

		(a)	(b)	(c)
			Value Line	
	Company	Expected ROE	Adjustment Factor	Adjusted ROE
1	AGL Resources, Inc.	13.0%	1.0304	13.4%
2	Atmos Energy Corp.	9.5%	1.0340	9.8%
3	Laclede Group	11.0%	1.0331	11.4%
4	Nicor, Inc.	11.5%	1.0247	11.8%
5	Northwest Natural Gas	11.0%	1.0298	11.3%
6	Piedmont Natural Gas	14.0%	1.0089	14.1%
7	South Jersey Industries	14.5%	1.0384	15.1%
8	Southwest Gas	8.5%	1.0307	8.8%
9	WGL Holdings, Inc.	11.0%	1.0198	11.2%
	Average (d)			**11.9%**

(a) Exhibit JRW-10, p. 4.
(b) Adjustment to convert year-end "r" to an average rate of return based on data from The Value Line Investment Survey (Mar. 12, 2010).
(c) (a) x (b).
(d) Excludes highlighted values.

ALLOWED ROE

BAUDINO PROXY GROUP

	Company	Allowed Return on Common Equity
1	ALLETE, Inc.	10.74%
2	Alliant Energy Corp.	10.41%
3	Con. Edison, Inc.	10.03%
4	DTE Energy Company	11.00%
5	Edison International	10.66%
6	Entergy Corporation	10.76%
7	Exelon Corporation	10.30%
8	IDACORP, Inc.	10.18%
9	Northeast Utilities	9.72%
10	Pepco Holdings, Inc.	10.15%
11	PG&E Corporation	11.35%
12	Progress Energy Inc.	12.00%
13	PS Enterprise Group	9.88%
14	Southern Company	11.93%
15	Wisconsin Energy Corp.	10.43%
16	Xcel Energy Inc.	10.72%
	Average	**10.64%**

Source: *AUS Monthly Report* (Apr. 2010).

WOOLRIDGE ELECTRIC PROXY GROUP

	Company	Allowed Return on Common Equity
1	ALLETE, Inc.	10.74%
2	American Electric Power Co.	10.66%
3	Central Vermont PS Corp.	10.71%
4	Cleco Corporation	10.70%
5	DPL Inc.	11.00%
6	Edison International	10.66%
7	Empire District Electric Co.	10.80%
8	FirstEnergy Corporation	10.67%
9	Hawaiian Electric Industries, Inc.	10.82%
10	IDACORP, Inc.	10.18%
11	Northeast Utilities	9.72%
12	NSTAR	12.50%
13	Pinnacle West Capital Corp.	11.00%
14	PPL Corporation	9.57%
15	Portland General Electric	10.80%
16	Progress Energy Inc.	12.00%
17	Southern Company	11.93%
18	UIL Holdings Corporation	8.75%
19	UniSource Energy Corporation	10.13%
20	Xcel Energy Inc.	10.72%
	Average	**10.70%**

Source: *AUS Monthly Report* (Apr. 2010).

ALLOWED ROE

WOOLRIDGE GAS PROXY GROUP

	Company	Allowed Return on Common Equity
1	AGL Resources, Inc.	10.52%
2	Atmos Energy Corp.	11.71%
3	Laclede Group	NA
4	Nicor, Inc.	10.17%
5	Northwest Natural Gas	10.20%
6	Piedmont Natural Gas	10.60%
7	South Jersey Industries	10.00%
8	Southwest Gas	10.20%
9	WGL Holdings, Inc.	10.20%
	Average	**10.45%**

Source: *AUS Monthly Report* (Apr. 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. 2009-00549

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

Filed: May 27, 2010

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 "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. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to affirm the importance of industrial customers to the Companies and the Commonwealth; (2) to rebut a proposed off-system-sales ("OSS") margin normalization adjustment proposed by Kentucky Industrial Utility Customers, Inc. ("KIUC") witness Lane Kollen; (3) to address several proposed pro forma adjustments proposed by Department of Defense/Federal Executive Agencies ("DOD/FEA") witness Thomas Prisco; (4) to address the concerns of low-income customers regarding ability to pay and late-payment charges; (5) to address the demand-side management assertions made by AARP witness Nancy Brockway; and (6) to address Kroger Company's request that LG&E consult with the Commission and customers before setting final policy on "triggers" for being placed on Rate DGGS from other gas rates.

<u>**The Importance of Industrial Customers**</u>

Q. The KIUC has submitted testimony by Dr. Paul Coomes in this proceeding to explain the importance of industrial customers to Kentucky's economy. What is LG&E's position on the importance of such customers?

A. There is no question about the importance of such customers. They are important to the Commonwealth's economy in terms of providing jobs and tax revenues, and they are important to LG&E and KU because they are the Companies' largest customers. Neither LG&E nor KU contests the importance of these customers to the Companies or the Commonwealth.

That notwithstanding, LG&E believes it has proposed fair, just, and reasonable rates in this proceeding, including those for industrial customers.

<u>Off-System Sales Revenues Should Not Be Normalized (KIUC/Kollen)</u>

Q. What standard applies to all pro forma adjustments?

A. The standard that applies to all pro forma adjustments made to historical-test-year results is 807 KAR 5:001 § 10(7): "[A] utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period."

Q. Does the off-system sales normalization Mr. Kollen proposes meet that standard?

A. No, it certainly does not. The data Mr. Kollen cites to support his adjustment show that the Companies' OSS margins have generally declined over the last five years. According to the testimony of the KIUC, the level of OSS margin credited to customers in the test year is $22.7 million ($18.2 million for LG&E, $4.5 million for KU); however, as the Company indicated in response to a KIUC data request, the actual OSS margin in the test year was $13.2 million ($9.1 million for LG&E, $4.1 million for KU).[1]

[1] First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. dated March 1, 2010 Question No. 66 (KU) and Question No. 63 (LG&E).

Q. Do you agree with Mr. Kollen's calculation of the OSS margin in the test year?

A. No. He apparently has taken the OSS revenues reported in the monthly environmental surcharge filings and the fuel expense from the monthly fuel adjustment clause filings to calculate the OSS margins in his testimony. This calculation mixes data from two different rate mechanisms and ignores the interaction between inter-company sales reflected in the fuel clause calculation. The calculation of the actual OSS margin in the test year ($13.2 million -$9.1 million for LG&E, $4.1 million for KU) presented in First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. dated March 1, 2010 Question No. 66 (KU) and Question No. 63 (LG&E) was done according to the methodology presented by LG&E and KU in regulatory filings to this Commission for at least the last ten years and properly reflects the appropriate revenues and expenses associated with OSS.

Q. Will you please explain why the off-system sales normalization Mr. Kollen proposes does meet the "known and measureable" standard?

A. Yes. Notwithstanding the error in his calculation of the OSS margins in the test year, in contrast the adjustment presented by Mr. Kollen, the data Mr. Kollen cites show that the Companies' OSS margins have generally declined over the last five years. The actual OSS margin in the test year was $13.2 million ($9.1 million for LG&E, $4.1 million for KU).[2] The Companies' projected OSS margin for calendar year 2011— Trimble County Unit 2 ("TC2") will be commercially operational the whole year—is just $11.8 million ($11 million LG&E, $800,000 for KU), which is in line with their test-year results. No party to these proceedings has challenged the

[2] First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. dated March 1, 2010 Question No. 66 (KU) and Question No. 63 (LG&E).

Companies' projections. Therefore, there is no "known and measurable change[]" that would support any pro forma adjustment to the historical test-year OSS margin amounts embedded in the Companies' proposed base electric rates; rather, the historical data Mr. Kollen cites, as well as the Companies' uncontested OSS margin projection for 2011, clearly demonstrate that the amount of OSS margins embedded in the Companies' proposed rates are reasonably indicative of the OSS margins that can be expected in the near term. Mr. Kollen's testimony fails to demonstrate that the KIUC's simple five-year average of OSS (calendar years 2005 to 2008 and the test year) is indicative of future OSS margins with any reasonable certainty.

Q. Why is the Companies' projected OSS margin for 2011 lower that the test year margin if TC2 will be in full commercial operation that year?

A. First, the Companies have experienced a reduction in generation sources in recent years. On December 31, 2005, KU's purchase contract with Electric Energy, Inc., expired on its own terms, resulting in a loss of 200 MW of firm, low-cost generation capacity. This month, KU's contract with Owensboro Municipal Utilities ("OMU") also expired, resulting in a loss of over 160 MW of summer-rated capacity. Therefore, though the addition of TC2 will result in a net generation capacity increase to the Companies, it is not as large as Mr. Kollen suggests. Moreover, Mr. Kollen's assertion that the Companies can expect higher OSS margins in the future because "[t]he Companies have added significant peaking capacity in recent years" cannot be supported by the facts.[3] The last peaking units (combustion turbines) the Companies put in service were Trimble County Units 9 and 10, which went in service on July 1,

[3] KIUC Response to KPSC 1-3.

2004, well before the test year in this proceeding, and even before the five years over which Mr. Kollen seeks to average OSS margins.

Second, as Mr. Kollen's own forward electric energy price curve shows, wholesale electric energy rates through 2015 (about $50.00/MWh in 2011, climbing to $57.00/MWh in 2014-2015) are not expected to come close to the levels achieved in 2005 ($76/MWh) and 2008 ($73/MWh), when the Companies' OSS margins were more substantial than in the test year. Including such aberrantly high-priced years in a normalization, when there is no expectation that such highs will be achieved again in the foreseeable future, would be blatantly results-oriented and selective in nature.

Third, any economic recovery in the Companies' service areas will likely lead to increased electric energy usage to fuel new economic activity, making less capacity and energy available for OSS. This fact undermines Mr. Kollen's assertion that a rebounding national economy will necessarily mean increased OSS margins for the Companies.[4]

All of these factors demonstrate that the amount of OSS margins embedded in the Companies' proposed base rates is reasonably representative of a going-forward level.

Q. Why wouldn't an OSS normalization adjustment be comparable to the other kinds of normalization adjustments the Companies have proposed?

A. There are precisely three kinds of normalization adjustments the Companies have proposed in these base rate proceedings: weather, storm damage, and injuries and

[4] KIUC Response to KPSC 1-4(a).

damages. Contrary to Mr. Kollen's exaggerated assertion, these are not "among others"; this is the entire list.

There is a reason the list is so short: they constitute exceptions to the rule I quoted above from 807 KAR 5:001 § 10(7): "[A] utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period." Mr. Kollen asserts that "Normalization adjustments are standard ratemaking practice."[5] They are no such thing, and certainly not before this Commission.

The few normalization exceptions to the general "known and measurable" rule exist primarily because the revenues or expenses being normalized are essentially random occurrences without any upward or downward trend that is incorporated into the adjustment. The weather will be what it will be, and what storms will come the Companies can neither predict nor affect. Furthermore, with temperature, storms and injuries and damages there is a central tendency for events to fall within a range that will typically equal a mean value when measured over time. While the number of heating degree days, cooling degree days, storms, or injuries vary from year to year, the average values of these random variables are very stable and predictable over time. Though the Companies strive to minimize injuries and damages and the effect of storms, they will occur, and in no discernible pattern. For these reasons, there is no reason to think that any given test year's storm or injuries and damages costs are indicative of future costs; what is normal can only be understood in reference to the past over a long span of time.

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[5] KIUC Response to KPSC 1-2(a).

Off-system sales, on the other hand, are not predictable or stable over long periods of time. They are subject to upward and downward cycles that are entirely unpredictable. They are heavily dependent on the economy, the price of fuel, demand for capacity, the relationship between supply and demand characteristics in the region, wheeling costs across transmission systems, and the Company's ability to market power to third parties, none of which can be described as a random variable with a identifiable central tendency.

The purpose of a establishing a test year in a rate case is to identify levels of revenues and expenses that are representative on a going forward basis. In offering his adjustment, Mr. Kollen is essentially supplanting what actually occurred during the test year and with his own prediction of what power markets will look like in the future. History has shown that such predictions are unreliable at best. But more significantly, Mr. Kollen's adjustment does not rise to the standard of being known and measurable.

Q. Has the Commission ever approved an OSS margin normalization adjustment of the kind Mr. Kollen proposes?

A. No, and Mr. Kollen frankly admitted as much in a response to a Commission Staff data request: "Mr. Kollen is not aware that ... the Commission has adopted a normalization adjustment to OSS margins based on average historic margins."[6] Nothing he has presented suggests the Commission should change its unbroken practice in this proceeding by adopting his purely results-oriented OSS margin normalization adjustment.

[6] KIUC Response to Commission Staff DR No. 2(a).

Q. What is the Companies' position on an OSS tracker mechanism of the kind Mr. Kollen suggests?

A. The imposition of surcharges in recent years under these circumstances has proven to be problematic. This is best illustrated by contrasting the position of KIUC in this case (i.e., proposing an OSS tracker) while vehemently opposing the Companies' renewable surcharge mechanism in the recent wind power proceeding, Case No. 2009-00353. Mr. Kollen is correct that the Companies' consent to such a tracker is typically required by the Commission before imposing such a significant change in regulation. For example, the Commission allowed the Companies to choose whether they would operate under the Earnings Sharing Mechanism several years ago. The Attorney General's consent to such a surcharge under the present circumstances is only a remote possibility.

The Commission's historic policy of including OSS margins in base rates has fairly balanced the interests of customers and shareholders, provided an appropriate and symmetrical incentive to maximize OSS margins when possible and shielded retail customers from the risks of the wholesale power market. Mr. Kollen has failed to present sufficient reasons or evidence why the Commission should deviate from its historic policy.

Economic Development Rider

Q. Would LG&E support an economic development rider to benefit Ft. Knox, as suggested by Department of Defense/Federal Executive Agencies ("DOD/FEA") witness Thomas Prisco?

A. On the basis of the criteria for economic development rates the Commission established in Administrative Case No. 327, LG&E cannot support Mr. Prisco's proposed economic development rider ("EDR").[7] In its September 24, 1990 order in Administrative Case No. 327, the Commission set out 18 findings and criteria concerning economic development riders. Those most pertinent to Mr. Prisco's proposal are:

> 1. EDRs will provide important incentives to new large commercial and industrial customers to locate facilities in Kentucky and to existing large commercial and industrial customers to expand their operations, thereby bringing much needed jobs and capital investment into Kentucky.
>
> 2. Utilities should have the flexibility to design EDRs according to the needs of their customers and service area and to offer EDRs to those new and existing customers who require such an incentive to locate new facilities in the state and to expand existing ones.
>
> 3. EDRs should be implemented by special contracts negotiated between the utilities and their large commercial and industrial customers.
>
> 4. An EDR contract should specify all terms and conditions of service including, but not limited to … the number of jobs and capital investment to be created as a result of the EDR ….
>
> …
>
> 10. The major objectives of EDRs are job creation and capital investment. However, specific job creation and capital investment requirements should not be imposed on EDR customers.
>
> 12. … For existing industrial customers, an EDR shall apply only to new load which exceeds an incremental usage level above a normalized base load. …
>
> 13. EDR contracts designed to retain the load of existing customers should be accompanied by an affidavit of the customer stating that, without the rate discount, operations will cease or be severely restricted. …[8]

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[7] *In the Matter of an Investigation into the Implementation of Economic Development Rates by Electric and Gas Utilities*, Admin. Case No. 327, Order at 25-28 (Sept. 24, 1990).
[8] *Id.* at 25-27.

In short, the only legitimate purpose for an economic development rate is to bring new, or to retain current, economic development. As Mr. Prisco frankly states in his testimony, his proposed EDR would accomplish no such thing; rather, in 2005 it was determined that Fort Knox would not only remain in operation, but would be expanded. The purpose Mr. Prisco posits for his proposed EDR is "to reward Fort Knox for the long range benefits it will provide to the LG&E system and its customers[.]" However laudable a purpose that might be, it is not a purpose the Commission has recognized as sufficient to support an economic development rate, so LG&E cannot support Mr. Prisco's proposal.

Moreover, the language quoted above from the Commission's order in Administrative Case No. 327 is clear that the means by which to implement an economic development rate is by negotiating a special contract between the customer and the utility, not by proposing a rider in a base rate proceeding. Indeed, the Commission's Administrative Case No. 327 order says that a company must show in base rate proceedings how customers are not being harmed by existing economic development rate special contracts;[9] it is not the forum in which to negotiate new economic development contracts.

Finally, the Kentucky Court of Appeals recently held in a unanimous decision that economic development rates and riders violate KRS 278.170.[10] Although the Kentucky Supreme Court has granted discretionary review of that decision, I respectfully submit that the significant uncertainty concerning the legal viability of all

[9] *Id.* at 26.
[10] *Commonwealth of Kentucky v. Public Service Commission of Kentucky and the Union Light, Heat, and Power Company*, 2006-CA-001652-MR, slip op. at 8-11 (Ky. App. 2008), *discret. rev. granted*, (Ky. Apr. 15, 2009) (Nos. 2008-SC-0483-D & 2008-SC-0489-D.

EDRs, as well as the fact that the DOD/FEA's proposed EDR does not meet the Commission's long-standing requirements for such rates, are more than sufficient reasons for the Commission to reject the DOD/FEA's proposed EDR.

Depreciation Expense

Q. Why is Mr. Prisco's adjustment to LG&E's depreciation expense for TC2 and its related transmission assets erroneous?

A. At page 13 of his testimony, Mr. Prisco proposes to reduce by 7/12 the amount of depreciation expense LG&E included for TC2 and its related transmission assets in Reference Schedule 1.15 to Rives Exhibit 1. He justifies his adjustment on the ground that TC2 "will only be online for five of the twelve months succeeding the test period." (I assume Mr. Prisco meant to say, "[W]ill only be online for five of the twelve months after LG&E's new rates will go into effect.") This adjustment is erroneous because, though TC2 will be commercially operational for only part of calendar year 2010, it will, barring the unforeseen, be commercially operational for all twelve months of each of many years to come. For that reason, it is appropriate to include an annualized amount of depreciation expense in LG&E's base electric rates (based on the TC2 construction-work-in-progress balance at the end of the test year) on a going-forward basis.

Puzzlingly, though, Mr. Prisco stated in response to a Commission Staff data request, "If TC 2 were commercialized in November 2009, I would allow full recovery of the depreciation expense."[11] Mr. Prisco appears not to understand that the Companies are seeking to include depreciation expense for only the TC2

[11] DOD/FEA Response to KPSC 1-3.

construction-work-in-progress balance at the end of the test year consistent with Commission precedent.[12] If TC2 had been in commercial operation in November 2009, including depreciation expense for the full amount for TC2 capitalization would have been appropriate, not the smaller amount of depreciation expense the Companies are actually proposing. In any event, Mr. Prisco's proposed reduction to LG&E's depreciation expense adjustment is unsupported and incorrect.

<u>Hazard Tree Program</u>

Q. Why is Mr. Prisco's adjustment to LG&E's Hazard Tree Program expense erroneous?

A. Mr. Prisco asks the Commission to strike LG&E's proposed Hazard Tree Program adjustment because, "[b]efore any new program is provided, LG&E should be required to competitively bid the requirements to see if the proposed costs are fair and reasonable." Contrary to what Mr. Prisco appears to believe, LG&E and KU will indeed competitively bid their Hazard Tree Program, and their cost projections are based on competitive bids for their current vegetation management program. Moreover, the Hazard Tree Program is a system hardening measure that Davies Consulting, Inc., recommended in its report detailing the findings of its investigation of the Companies' responses to the 2009 Winter Storm ("Davies Report"). Thus, because the proposed cost would be incurred prudently to minimize future storm damage, the Commission should accept it.

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[12] *In the Matter of: Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company*, Case 90-0158, Order, pp. 6, 32 (December 21, 1990).

Low-Income Concerns

Q. What is LG&E's response to concerns that low-income and fixed-income customers may have difficulty paying LG&E's requested rates?

A. We sympathize with the difficulties these groups face, and will continue efforts to assist these customers. For example, LG&E sought and received approval from the Commission in 2007 to continue the Home Energy Assistance ("HEA") Program, which provides hardship assistance to low-income customers through the collection of 15 cents per residential meter per month. LG&E has also implemented a FLEX program to allow customers on fixed incomes 16 additional days to pay their bills (i.e., their bills are due 28 days from the bill date), effectively allowing participating customers to pay their bills after they receive their monthly incomes. Finally, LG&E personnel continue to work with low-income groups' representatives, meeting regularly in working groups to address new and ongoing needs, issues, and concerns.

Q. Can LG&E waive late-payment charges for low-income customers?

A. Association of Community Ministries witness Marlon Cummings suggests in his testimony that LG&E should waive late-payment charges for low-income customers; however, LG&E does not have the authority to waive late-payment charges for low-income customers. First, LG&E must follow its tariff:

> No utility shall charge, demand, collect, or receive from any person a greater or less compensation for any service rendered or to be rendered than that prescribed in its filed schedules, and no person shall receive any service from any utility for a compensation greater or less than that prescribed in such schedules.[13]

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[13] KRS 278.160(2).

Second, LG&E must treat equally all customers in a rate class:

> No utility shall, as to rates or service, give any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage, or establish or maintain any unreasonable difference between localities or between classes of service for doing a like and contemporaneous service under the same or substantially the same conditions.[14]

The Commission has rejected income level as a reasonable ground for maintaining any distinction between customers.[15] For these reasons, LG&E simply cannot waive late-payment charges for low-income customers.

DSM Program Spending

Q. AARP witness Nancy Brockway suggests that more DSM spending should accompany increased rates. How does LG&E respond?

A. As Mr. Seelye testified earlier in this proceeding, "LG&E and KU are currently doing more in the area of demand-side management, energy efficiency and energy conservation than any of the other utilities in Kentucky." Ms. Brockway seems to believe the Companies should do more, though she acknowledges she does not know how the Companies' programs in this area or their spending thereon compare to other utilities.

In fact, the Companies are very much engaged in these fields, including their responsive pricing and smart metering pilot program, as discussed in Mr. Wolfram's testimony (which Mr. Cockerill has adopted). In addition, the Companies are constantly looking for additional cost-effective DSM/EE programs to implement for

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[14] KRS 278.170(1).

[15] *In the Matter of Application for Adjustment of Electric Rates of Kentucky Power Company*, Case No. 1991-00066, Order (Oct. 31, 1991); *In the Matter of the Consideration of Life-Line Rates as Required by Section 114 of the Public Utility Regulatory Policies Act*, Administrative Case No. 248, Order (Feb. 28, 1982).

their customers' benefit. But simply spending more money on such programs does not guarantee commensurate savings to customers, nor would such spending be reflected in the Companies' base rates, because the funding for DSM/EE programs comes from each of the Companies' DSM Cost Recovery Mechanisms.

Even with the excellent suite of DSM/EE programs LG&E and KU have deployed, their customers still require electric capacity and energy, which the Companies are privileged to supply in return for fair, just, and reasonable rates. Those are what LG&E have proposed in this proceeding, and are the appropriate subject matter of this proceeding.

Rate DGGS

Q. Has LG&E agreed to make changes to the Rate DGGS tariff sheet since filing its base rate application in this proceeding?

A. Yes. LG&E now proposes to exempt from the application Rate DGGS locations that install back-up generators using less than 2,000 cf/hr (approximately equivalent to a 200 kVA gas-fired generator) if the customers who own such generators agree to use them only to provide emergency power. A revised tariff sheet for Rate DGGS is attached a Bellar Rebuttal Exhibit 1.

Q. In response to data requests from Kroger, LG&E referred to changes in a customer's status that might trigger the loss of the grandfathering exemption covering that customer's gas-fired generator. Are those triggers still valid?

A. Yes. LG&E identified two triggers that would cause a customer's gas-fired generation facility to lose its grandfathered status and be transferred to Rate DGGS:

- As with any customer transferring between rate schedules, customers with gas-fired generation installations transferring to Rate FT from other rate schedules would be required to take service under Rate DGGS for any generation load.[16]

- Any modifications to metering, regulation, or other service facilities of Company that are required to accommodate a change in size of load or in load characteristics of a customer may trigger the transfer of the customer's gas-fired generation facilities to Rate DGGS.[17]

Kroger, in its testimony, indicated that "these are the type of changes that might be reasonably accommodated within a customer's business planning processes" and that LG&E should give notice to the Commission and customers of such policies regarding these triggers.[18] LG&E believes that these triggers, as identified above, are specific enough not to warrant further disposition. If LG&E's policies are supplemented or modified in this regard in the future, LG&E can, at the Commission's request, notify the Commission.

Q. Does this conclude your testimony?

A. Yes.

[16] LG&E Response to Question No.13 of the First Data Request of the Kroger Company dated March 1, 2010.
[17] LG&E Response to Question No.15 of the First Date Request of the Kroger Company dated March 1, 2010.
[18] Kroger/Townsend Testimony at p. 16.

VERIFICATION

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

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Louisville Gas and Electric Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that 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 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

Bellar Rebuttal Exhibit 1

Louisville Gas and Electric Company

Standard Rate **DGGS**

Distributed Generation Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to customer-owned electric generation facilities except (i) when such natural gas is limited to the production of electricity for Customer's own use during emergency situations during which Customer's normal supply of electricity is not otherwise available, and (ii) when such electric generation facilities have a total connected load of less than 2,000 cubic feet per hour. Natural gas purchased for electric generation facilities with a total connected load of 2,000 or more cubic feet per hour, or purchased to generate electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electrical supplies during emergency situations shall be subject to this tariff. Additionally, service under this Standard Rate DGGS shall be applicable only to electric generation facilities described above and installed and operating on and after ninety (90) days after the effective date of Rate DGGS (and therefore not eligible for service under Standard Rates CGS or IGS) by commercial and industrial customers. T

Deleted: that consume natural gas to produce electricity for Customer's own use, for further distribution, for sale in the open market, or for any other purpose

Service hereunder shall be at a single delivery (custody transfer) point and where distribution mains are adjacent to the premises to be served. Gas sales service provided hereunder shall be metered and billed separately from gas service provided under any other rate schedule.

Sales service hereunder shall be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other customers. Company may decline to accept customers under this rate schedule with a connected load of more than 8,000 cubic feet per hour. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this rate schedule.

If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, such residential customer shall be served under Rate DGGS.

CHARACTER OF SERVICE

Gas sales service under this rate schedule shall be considered firm.

RATE

In addition to any other charges set forth herein, the following charges shall apply.

Basic Service Charge: T

If all of the customer's meters have a capacity < 5000 cf/hr:	\$ 30.00 per delivery point per month
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	\$170.00 per delivery point per month

Date of Issue: January 29, 2010
Date Effective: March 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

Louisville Gas and Electric Company

Standard Rate DGGS

Distributed Generation Gas Service

T

Demand Charge per 100 cubic feet of Monthly Billing Demand:	$1.0110	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$0.02744	I
Gas Supply Cost Component	0.53494	
Total Charge Per 100 Cubic Feet	$0.56238	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

The total monthly minimum bill shall be the sum of the minimum monthly Demand Charge and the Monthly Basic Service Charge. T T

In no case shall Company be obligated to deliver greater volumes hereunder than those specified in the written contract between Customer and Company. Payment of any and all charges hereunder shall not be considered an exclusive remedy for takes in excess of the maximum daily quantity ("MDQ"), nor shall the payment of such charges be considered a substitute for any other remedy (including, but not limited to, physical discontinuance or suspension of service hereunder) available to Company.

ADJUSTMENT CLAUSES

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

Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL

Customer's payment will be due within twelve (12) days from the date of the bill. T

LATE PAYMENT CHARGE

If full payment is not received within three (3) days from the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

Date of Issue: January 29, 2010
Date Effective: March 1, 2010
Issued By: Lonnie E. Bellar, Vice President, State Regulation and Rates, Louisville, Kentucky

SPECIAL TERMS AND CONDITIONS T

1. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be sold by Company to Customer, and any other matters relating to individual customer circumstances.

2. The minimum contract term for service hereunder shall be for a period not less than five (5) years commencing from the effective date thereof.

3. Such written contract shall specify the minimum delivery pressure, the maximum hourly rate ("MHR"), and the maximum daily quantity ("MDQ"). The MHR is the maximum hourly gas load in 100 cubic feet that the Customer's installation will require when operating at full capacity. The MDQ shall be twenty-four (24) times the MHR. The MDQ is the Monthly Billing T
Demand and shall not be less than 10 (ten) Ccf. T

4. In no case shall Company be obligated to make deliveries hereunder at a pressure greater than thirty (30) psig, or the prevailing line pressure, whichever is less.

5. Increases in the MDQ may be requested annually by Customer. Customer may request Company to increase the MDQ at least ninety (90) days in advance of the anniversary date of the written contract. Such increases in the MDQ that are acceptable to Company in its sole discretion shall be effective on the anniversary date of the effective date of the written contract.

6. In the event that Company agrees to install any Company-owned facilities required to serve T
Customer, such facilities to be installed by Company shall be specified in the written contract and the cost of such facilities and installation thereof shall be paid by Customer to Company.

TERMS AND CONDITIONS

Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

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. 2009-00549

REBUTTAL TESTIMONY OF
ROBERT M. CONROY
DIRECTOR, RATES
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: May 27, 2010

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

A. My name is Robert M. Conroy. I am the Director of Rates for E.ON U.S. Services Inc., which provides services to Louisville Gas and Electric Company ("LG&E" or "Company") and Kentucky Utilities Company ("KU") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky.

Q. What are the purposes of your testimony?

A. The purpose of my testimony is to address and respond to certain points and assertions made by intervenors to this proceeding. Specifically, I will address intervenors' comments on the following topics: (1) the percentage used to calculate off-system sales revenues for Environmental Cost Recovery ("ECR"); (2) the adjustment to ECR if the Commission normalizes off-system sales margins; and (3) statements by the Kentucky School Board Association witness regarding application of the appropriate tariff for schools.

Off-System Sales ("OSS") Revenues Calculation for ECR

Q. Please describe the intervenors' objection to the Company's adjustment to reduce OSS revenues for the portion of the ECR revenue requirement allocated to off-system sales.

A. Mr. Lane Kollen, testifying on behalf of the Kentucky Industrial Utility Customers, Inc., is the only intervenor who objected to the Company's adjustment.[1] While Mr. Kollen accepts the purpose of the adjustment, his disagreement is in how the adjustment was calculated. Mr. Kollen objects to LG&E's use of an annualized

[1] Direct Testimony of Lane Kollen of April 22, 2010 (Case No. 2009-00549) at 8-9.

simple average of surcharge factors (percentages), arguing that a weighted average percentage should be utilized because OSS revenues and the ECR factors vary considerably each month.[2] Mr. Kollen argues that use of the simple average results in an overstatement of the average ECR factor, which results in a greater reduction in OSS revenue.

Q. Why does the Company currently use a simple average in the calculation?

A. As explained in response to KPSC 2-33, the simple average is utilized because it is consistent with the method the Commission adopted in Case No. 98-426. Further, this method has been used consistently by LG&E in all base rate proceedings since that proceeding. Although Mr. Kollen's testimony states that the Company "provided corrected computations" in response to KPSC 2-33, which asked LG&E to provide a revised version of the calculation using the weighted average approach, this contention is inaccurate.[3] The Company's use of the simple average was not incorrect, as LG&E was complying with established Commission precedent.

Q. Does LG&E object to Mr. Kollen's position as to the use of a weighted average?

A. No. LG&E believes that use of the simple average, as well as the weighted average, are reasonable approaches. The Company does agree that the weighted average is mathematically more accurate.[4] While the Company does not object to use of the weighted average, it is not appropriate to continuously vacillate between the simple average and weighted average methods. If the Commission recommends use of the weighted average in this proceeding, Mr. Kollen and the other intervenors should not

[2] Id. at 9.
[3] Id. at 9.
[4] See LG&E's response to KPSC 3-16.

argue for use of the simple average in LG&E's subsequent base rate proceedings merely because use of the simple average may result in a greater reduction in the revenue requirement than the weighted average. While the Company is amenable to either approach, it is important that the Commission establish a consistent methodology for this computation.

Adjustment to ECR Calculation for Normalized OSS Margins

Q. Briefly explain the intervenors' adjustment to OSS margins.

A. Mr. Kollen has proposed an adjustment to normalize OSS margins.[5] Additionally, Mr. Kollen has asserted that if the Commission allows his adjustment to normalize OSS revenues, his adjustment to the ECR calculation discussed above will have to be increased from the exhibit Mr. Kollen included in his direct testimony to reflect any base rate increases authorized in this proceeding. LG&E objects to Mr. Kollen's adjustments regarding OSS normalization for the reasons explained in Mr. Lonnie Bellar's rebuttal testimony in this proceeding.

Appropriate Tariff for Schools

Q. Mr. Charles D. Buechel, a witness on behalf of the Kentucky School Boards Association, asserts that the appropriate tariff for schools has not always been utilized.[6] Can you comment on this assertion?

A. Yes. Although Mr. Buechel made the indication in testimony, he subsequently, when questioned by the Commission,[7] indicated that he had no direct information that

[5] Id. at 10-11.
[6] Direct Testimony of Charles D. Buechel of April 22, 2010 (Case No. 2009-00549) at 5.

schools were served under inappropriate rates. When customers initiate service for their facility, the Company does its best to put them on the rate schedule that is applicable for their service. However, the responsibility when two or more rate schedules are available to a customer is specifically stated in the Terms and Conditions, Original Sheet No. 97, of the Company's Tariff:

> OPTIONAL RATES
>
> If two or more rate schedules are available for the same class of service, it is Customer's responsibility to determine the options available and to designate the schedule under which customer desires to receive service.
>
> Company will, at any time, upon request, advise any customer as to the most advantageous rate for existing or anticipated service requirements as defined by the customer, but Company does not assume responsibility for the selection of such rate or for the continuance of the lowest annual cost under the rate selected.
>
> In those cases in which the most favorable rate is difficult to predetermine, Customer will be given the opportunity to change to another schedule, unless otherwise prevented by the rate schedule under which Customer is currently served, after trial of the schedule originally designated; however, after the first such change, Company shall not be required to make a change in schedule more often than once in twelve (12) months.
>
> From time to time, Customer should investigate Customer's operating conditions to determine a desirable change from one available rate to another. Company, lacking knowledge of changes that may occur at any time in Customer's operating conditions, does not assume responsibility that Customer will at all times be served under the most beneficial rate.
>
> In no event will Company make refunds covering the difference between the charges under the rate in effect and those under any other rate applicable to the same class of service.

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[7] See Kentucky School Board Association's Response to KPSC 1-1.

While the Company will work with customers on requesting service, the customer is in a better position to understand their load characteristics and determine the rate schedule that will minimize the cost of energy for their facilities.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Director - Rates for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 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. 2009-00549

REBUTTAL TESTIMONY OF
SIDNEY L. "BUTCH" COCKERILL
DIRECTOR, REVENUE COLLECTIONS
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: May 27, 2010

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

A. My name is Sidney L. "Butch" Cockerill. I am the Director, Revenue Collections for E.ON U.S. Services Inc., which provides services to Louisville Gas and Electric Company ("LG&E" or "Company") and Kentucky Utilities Company ("KU") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202. A statement of my qualifications is included in the Appendix attached hereto.

Q. Have you testified previously before the Commission?

A. Yes, I have previously testified before the Commission, and did so in the Company's last general rate case, Case No. 2008-00252. In addition, I testified in Case Nos. 2007-00117 and 2007-00161, concerning responsive pricing and real-time pricing pilot programs, respectively.

Q. Are you adopting the testimony of John Wolfram as your own in this proceeding?

A. Yes. Mr. Wolfram is no longer with the Company, so I am adopting his pre-filed direct testimony as my own.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to confirm that LG&E has determined to rescind its proposal to allow only those customers who have not been disconnected for non-payment to pay any necessary deposits in installments; and (2) to support LG&E's proposed increase in the amount of its residential deposit.

Q. What is LG&E's proposal concerning payment of deposits in installments, and why?

A. LG&E proposes not to alter the deposit installment options currently available to customers required to make a deposit as a condition of reconnection. These options currently include, and will continue to include, allowing customers who have been disconnected for non-payment to pay required deposits in up to four installments upon request. LG&E's initial proposal to disallow that option was based on incomplete deposit installment payment default data. On further review, LG&E determined the proposal is not necessary and has rescinded it.

Q. What is your response to criticisms of LG&E's proposed increase in its deposit amount for residential electric customers?

A. LG&E's proposal to increase its residential electric customer deposit from $135 to $160 is well within the parameters set for such deposits by the relevant Commission regulation, 807 KAR 5:006 § 7(1)(b). (As shown in Seelye Exhibit 14, a deposit amount of $164 would be justified under LG&E's proposed rates.) That amount is less than an average residential customer's bill for two months under the proposed electric rates, which is the standard the Commission regulation establishes.

At just $25, the amount of the increase should not pose a significant problem to most customers, particularly in light of the fact that LG&E allows customers to pay their deposits in up to four monthly installments. Moreover, LG&E does not require deposits from all customers, but only those whose credit histories indicate they are credit risks. Most of LG&E's residential customers will not be impacted.

It is important to remember that the purpose of a deposit, or an increase thereof, is not to increase revenues or profits for LG&E; rather, it is a loss-prevention measure, and it comes at a cost. KRS 278.460(1) requires LG&E to pay interest on all deposits it holds at a statutory annual interest rate of 6%. That rate exceeds LG&E's costs of short- and long-term debt (see Rives Exhibit 2), and is several times higher than currently available one-year certificate of deposit rates.[1] In other words, it is costly for LG&E to hold customers' deposits, and it does so only to minimize the losses associated with customers' non-payment of their electric bills.

Finally, it should be noted that the Company is proposing to decrease the deposit for a gas customer from $160 to $115. Therefore, for combination electric and gas residential customers, the total deposit amount LG&E proposes ($275) is less than the current combined deposit ($295).

Q. Does this conclude your testimony?

A. Yes, it does.

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[1] *See* http://www.bankrate.com.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Sidney L. "Butch" Cockerill**, being duly sworn, deposes and says that he is Director – Revenue Collections for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Sidney L. "Butch" Cockerill
Sidney L. "Butch" Cockerill

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

APPENDIX A

S. L. "Butch" Cockerill
Director, Revenue Collections
E.ON U.S. Services Inc.
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40202
(502) 627-4772

Education

Spaulding University, B.A. in Business Administration – 1998

Previous Positions

Louisville Gas and Electric Company, Louisville, Kentucky
2002-2003 - Director of Distribution Operations
2000-2002 - Director of Gas Control and Storage
1997-2000 - Manager of Gas Storage Operations
1995-1997 - Manager of Gas Distribution
1990-1995 - Manager of Transportation Department

Professional Trade Memberships

American Gas Association
Kentucky Gas Association
Electric Utilities Fleet Management

Civic Activities

Kentucky Derby Festival, Director

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

APPLICATION OF LOUISVILLE GAS	)	
AND ELECTRIC COMPANY FOR AN	)	**CASE NO. 2009-00549**
ADJUSTMENT OF ITS ELECTRIC	)	
AND GAS BASE RATES	)	

RECEIVED
MAY 27 2010
PUBLIC SERVICE COMMISSION

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

Filed: May 27, 2010

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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" or "Company").

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 concerning his proposed electric and gas cost of service studies, revenue allocation, and rate design; Kentucky Industrial Utility Customers, Inc. ("KIUC") witness Stephen J. Baron concerning electric cost of service and rate design; KIUC witness Dennis W. Goins concerning his recommendations regarding curtailable electric service; KIUC witness Lane Kollen regarding unbilled revenues; The Kroger Co. ("Kroger") witness Neal Townsend concerning his recommendations to implement conjunctive demand billing; The Kentucky Cable Telecommunications Association ("KCTA") witness Patricia D. Kravtin regarding cable television pole attachment charges; AARP witness Nancy Brockway concerning electric and gas rate design and customer deposit requirements; and Kentucky School Board Association ("KSBA") witness Charles D. Buechel concerning electric rate design.

II. ELECTRIC CLASS COST OF SERVICE AND THE ALLOCATION OF THE REVENUE INCREASE

A. ALLOCATION OF FIXED PRODUCTION COSTS

Q. Is there agreement among the intervenor witnesses on the methodology that should be used to allocate costs in the class cost of service study?

A. No. In this proceeding, LG&E submitted a class cost of service study using a methodology that was first adopted by the Company in the early 1980s. On a number of occasions, the Commission has determined that the Company's cost of service study is reasonable and should be used as a guide for setting rates. A critical facet of the cost of service study is the methodology used to allocate fixed production costs (i.e., production capacity costs). As in prior rate case filings, the Company proposed to allocate fixed production costs using the modified Base-Intermediate-Peak ("BIP") methodology. Under the modified BIP methodology, a portion of fixed production costs are classified as "summer peak" costs and allocated on the basis of each customer class's loss-adjusted contribution to the system peak demand during the Summer ("summer coincident peak allocator"); another portion of fixed production costs are classified as "winter peak" costs and allocated on the basis of each customer class's loss-adjusted contribution to the system peak demand during the Winter ("winter coincident peak allocator"); and the remaining portion of fixed production costs are classified as "base" costs and allocated on the basis of each customer class's average demand ("average demand allocator").

A critical difference among the intervenor witnesses is the amount of fixed production costs allocated on the basis of an average demand allocator. In LG&E's cost of service study, 34.89% of fixed production costs were allocated on the basis of an average demand allocator. Mr. Baron, testifying on behalf of KIUC, and Mr. Selecky, testifying on behalf of Walmart in Case No. 2009-00548, the Kentucky Utilities Company ("KU") proceeding, both maintain that the modified BIP methodology allocates *too much* of the Company's fixed production costs on the basis of an average demand allocator; whereas, Mr. Watkins, who is testifying on behalf of the AG, maintains that the modified BIP methodology allocates *too little* of the Company's fixed production costs on the basis of an average demand allocator.

Because fixed production costs represent approximately 37% of the total cost of service, modifying the allocation factor used to assign these costs would have a significant impact on the results of the cost of service study. Allocating a larger percentage of fixed production costs on the basis of a demand allocator tends to shift costs to customer classes that use capacity *less efficiently.* Conversely, allocating a larger percentage of fixed production costs on the basis of an average demand allocator tends to shift costs to customer classes that use capacity *more efficiently.* In this context, "efficiency" relates to the extent to which the capacity is fully utilized and is generally measured by the load factor of a customer class. Greater utilization of the fixed assets corresponds to greater efficiency and a higher load factor. Lower utilization of the fixed assets corresponds to lesser efficiency and a lower load factor. The efficient utilization of capacity is not something that is considered only in the utility industry. Rather, it is a concept that is extremely important in any capital intensive industry – such as the airline industry or the shipping industry. For example, it is more efficient, and extremely important, for an airline to fill all of the seats on its planes, for a railway company to fill all of the cars on its trains, and for an overseas shipping company to fill all of the holds in its ships. A standard objective of companies operating in capital intensive industries is to maximize the utilization of their capacity. Companies operating in capital intensive industries are continuously looking for creative ways to increase the load factor and utilization of their capital investments.

Q. How do the witnesses propose to allocate fixed production costs?

A. Mr. Selecky proposes to allocate all fixed production costs on the basis of a coincident peak allocator. He argues that because a portion of fixed costs are allocated on the basis of an average demand allocator the modified BIP methodology "double counts" a portion of the average demand which is also included in the peak demand. Mr. Selecky argues as follows:

> By allocating some capital costs relative to average demand, and some relative to coincident peak demand, energy is counted twice – once by itself and the second time as a subset of the coincident peak. If the year-round energy is analogous to base load units, which supply capacity on a continuing basis throughout the year, then it follows that the only time when intermediate and peaking units would be needed to meet the system demands are when they are in excess of the average year demand. The BIP method improperly allocates the cost of this additional capacity relative to the total coincident demand, rather than the excess demand. (Case No. 2009-00548, Direct Testimony of James T. Selecky, pp. 8-9.)

Although he does not advance an alternative cost of service methodology, Mr. Baron maintains also that the modified BIP methodology allocates too much costs on the basis of an average demand allocator. Mr. Baron makes the following statement regarding the Company's cost of service methodology:

> While I do not believe that the BIP methodology is the most reasonable approach to class cost of service analysis, I have relied on this methodology in this case. In particular, the BIP method tends to allocate a greater percentage of the Companies' production and transmission costs to high load factor industrial rate classes because a significant portion of these costs are allocated as energy related (the base portion of the BIP method). (Case Nos. 2009-00549 and 2009-00548, Direct Testimony of Stephen J. Baron.)

Mr. Watkins, on the other hand, maintains that the Company's cost of service study does not allocate enough costs on the basis of average demand. Specifically, Mr. Watkins proposes to allocate 82.12% of the Company's fixed production costs on the basis of an average demand allocator. He argues that because a large percentage of the Company's production capacity is made up of coal-fired steam units, the original BIP methodology would have allocated most of LG&E's production fixed costs on the basis of an average demand allocator.

The following table illustrates the positions of the parties regarding the percentage of fixed production costs that should be allocated on the basis of demand and energy:

Percentages of Fixed Production Cost Allocated on the Basis of Peak and Average Demand		
Party	**Percentage Allocated on Peak Demand**	**Percentage Allocated on Average Demand**
AG (Mr. Watkins)	17.88%	82.12%
LG&E	65.11%	34.89%
KIUC (Mr. Baron)	Something greater than 65.11%	Something less than 34.89%
Walmart (Mr. Selecky)	100.00%	0.00%

As can be seen from this table, the percentage of production fixed costs allocated on the basis of demand or energy in the Company's cost of service study falls between the positions advocated by other parties in this proceeding. Because the Company is trying to balance the interests of all customer classes, LG&E's recommendation should be given greater weight in this proceeding.

Q. **Do you agree with Mr. Selecky's or Mr. Baron's argument that the modified BIP methodology allocates too much cost on the basis of an average demand allocator?**

A. I agree that care must be taken in any cost of service study to avoid allocating too large of a percentage of fixed production costs on the basis of average demand. From a purely academic perspective, changes in a customer class's average demand do not have any impact on the Company's capacity costs. For example, the Company's fixed production costs will not increase if any given customer class were to increase its average demand without altering its contribution to the system peak demand. The converse, however, is not true. Except in situations where prolonged periods of excess capacity exist, if a customer class increases its demand at the time of the peak without altering its average demand, then the utility's fixed production costs will certainly increase over time. Particularly, the utility will need additional generation capacity to meet the increase in peak demand. The same result is applicable in any capital intensive industries. Recalling the earlier example from the airline industry, increasing the *average* number of passengers on a flight (or flights) will not have any impact on an airline's *fixed* costs. Increasing the maximum number of passengers on flights can have a dramatic impact on fixed costs, including creating the necessity to buy additional planes, which, like power plants, are not inexpensive.

Mr. Selecky makes the somewhat arcane but not incorrect argument – akin to the mean value theorem in mathematical statistics – that any average number is numerically included within a maximum number. But the crux of his and Mr. Baron's argument seems to be that average demand has little or nothing to do with capacity costs. A further point of theirs is that allocating fixed production costs on the basis of average demand penalizes efficient utilization of capacity and rewards inefficient utilization of capacity – sort of like the absurd proposition of an airline awarding *infrequent flier miles* rather than *frequent flier miles*. In fact, many airlines have developed revenue management systems designed to maximize the revenue collected from each flight by increasing load factor and implementing tiered pricing structures. These sophisticated revenue management models often involve complex dynamic programming algorithms to target discretionary fliers and to deal with overbooking situations. See Kalyan T. Talluri and Garrett J. Van Ryzin, *The Theory and Practice of Revenue Management* (Springer, 2005), especially chapters 1, 2, and 4.

From an economics and production planning perspective, Mr. Selecky and Mr. Baron make cogent points. But relying entirely on a coincident peak allocator has its own problems. Using a coincident peak allocator will often result in free riders. For example, if a particular rate class – such as outdoor lighting or a set of industrial loads with unusual operating characteristics – is completely off line at the time of the system peak, then the rate class will not be allocated any fixed production costs. Consequently, the customer would not make any contribution toward the utility's fixed production costs. From a purely economic and production planning perspective, allocating no fixed production costs to outdoor lighting may make perfect sense, but from a marketing or regulatory policy perspective such a result is unreasonable. A utility's generation capacity is used to provide service to customer classes that may not contribute much to peak, and customers in these classes derive some benefit from the utility's generation. This is the regulatory policy basis for assigning some fixed production costs to all classes on the basis of average demand. The issue is how much fixed production cost to assign in an effort to balance the system planning and regulatory policy perspectives.

Q. Do you agree with Mr. Watkins that almost all fixed production costs should be allocated on the basis of average demand?

A. No. In Mr. Watkins' cost of service study, approximately 82% of LG&E's fixed production and transmission costs are allocated on the basis of an energy allocator. Other than the studies performed by Mr. Watkins, I cannot 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% of these capacity costs on the basis of an energy allocator. Allocating 82% of the Company's production and transmission capacity costs on the basis of energy is a direct consequence of his misapplication of the 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 82% of production capacity costs on the basis of energy cannot be supported by cost of service principles.

Q. How does Mr. Watkins misapply the BIP methodology?

A. Mr. Watkins attempts to use the original BIP methodology developed on an experimental basis to assign fixed production costs to costing periods in accordance with studies that were being conducted in the late 1970s related to requirements set forth in the Public Utilities Regulatory Policy Act. To my knowledge, the original

BIP methodology was never adopted by any regulatory commission. The original BIP methodology was abandoned 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 a couple of 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 1, Mr. Watkins' cost of service study produces off-peak fixed production costs of $0.019 per kWh and winter on-peak fixed production costs of $0.005. 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, an argument can be made that production capacity costs are zero during the off-peak period.

Q. Do you believe that the Company's cost of service study strikes a reasonable balance in the amount of fixed production costs allocated on the basis of average demand?

A. I believe that it does. In Mr. Watkins' study, far too much fixed production cost is allocated on the basis of average demand Furthermore, unlike Mr. Selecky's alternative, the Company's study avoids the possibility of allocating zero fixed production costs to rate classes that happen to be off the peak, such as outdoor lighting classes. An argument can certainly be made that some small portion of the Company's fixed production costs should be allocated on the basis of average demand to account for the fact that there is some value associated with the "utilization" of capacity, even though, from a purely economic and production planning perspective, average demand does not have any impact on the cost of providing service. In prior rate case orders, the Commission has determined that it is reasonable to allocate at least some portion of fixed production costs on the basis of "utilization". If the Commission continues to adhere to this policy, then a percentage determined by dividing the system minimum demand by the system maximum demand – which is the approach used in the modified BIP methodology – continues to be reasonable. The rationale for continuing to use the relationship of the minimum system demand to the maximum system demand for purposes of determining the percentage of fixed production costs to be allocated on the basis of "utilization" is that the Companies' production facilities will always supply an amount of production capacity at least equal to the minimum demand. Consequently, this minimum percentage of production capacity will be "utilized" each and every hour of the year. Thus, each rate class, regardless of when it needs the capacity, will be making at least some contribution to this minimum percentage of capacity.

C. ZERO INTERCEPT METHODOLOGY

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 central 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 arithmetic 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, R, and Matlab. Weighted least squares regression is also an accepted methodology covered in most standard reference books on multiple regression analysis.[1] If weighted least squares regression were merely a "clever arithmetic 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.

Mr. Watkins seems to be concerned about the presence of square roots in the weighted regression equation. The square root terms in the equation are simply a

[1] 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). Weighted least squares is also covered in numerous textbooks on econometrics. For example, see J. Johnson, *Econometric Methods*, Third Edition ((McGraw-Hill Book Company, 1983), pp. 293-296; and Potluri Rao and Roger LeRoy Miller, *Applied Econometrics* (Wadsworth Publishing Company, 1971), pp. 116-121. As explained in these texts, weighted least squares is necessary to account for the heteroscedasticity introduced from using average summary, or aggregated data in a regression analysis. A copy of the sections dealing with weighted least squares is included in Seelye Rebuttal Exhibit 2.

product of the analytical derivation of the weighted regression equations.[2] However, even without understanding the mathematics involved, the Company's results can be verified easily by using the weighted regression option in any standard statistical software package. Seelye Rebuttal Exhibit 3 shows the output from performing a weighted regression analysis for overhead conductor using the statistical software package R. R is an open source statistical package heavily used in academia and has similar functionality to the commercially available statistical software package S-Plus. As can be seen from page 2 of this exhibit, a weighted regression analysis performed using R yields the same results as the spreadsheet model used in the Company's analysis. Using either R or the Company's Excel spreadsheet model, the zero intercept is 0.756973. Over the years, I have verified the results of the Company's model using other commercially available statistical software packages, such as SAS and S-Plus.

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[2] In weighted least squares regression, the objective is to determine the parameters that minimize the least squares equation with the squared difference of each observation weighted by the number of items N_i (e.g., number of poles or feet of conductor), as follows:

$$\text{Sum of Weighted Square Differences} = \sum_{i=1}^{n} N_i(\hat{y} - y_i)^2$$
$$= \sum_{i=1}^{n} N_i([a + bx_i] - y_i)^2$$
$$= \sum_{i=1}^{n} \left([a\sqrt{N_i} + bx_i\sqrt{N_i}\,] - y_i\sqrt{N_i}\right)^2$$

This last equation is the same as a multivariable least squares problem with no intercept, using $\sqrt{N_i}$ as the first independent variable, $x_i\sqrt{N_i}$ as the second independent variable, and $y_i\sqrt{N_i}$ as the dependent variable. Although Microsoft Excel does not have a weighted regression option, a weighted regression model can be developed in Excel using the no-intercept option of the LINEST function in Excel to perform a regression model with $\sqrt{N_i}$ and $x_i\sqrt{N_i}$ as the two independent variables and $y_i\sqrt{N_i}$ as the independent variable. This approach will produce the same result as using a weighted regression analysis performed in SAS, S-Plus, R, etc.

Q. Why is it necessary to use weighted regression in performing a zero intercept analysis?

A. 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 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 2,210 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 there would be 2,210 data points for the 25 KVA transformers and only five data points for 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 the 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 <u>*weighted*</u> by feet or investment in each category, and developing a cost for the utility's minimum size conductor.
>
> **Account 366 and 367 – Overhead Conductors and Devices**
>
> - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable <u>*weighted*</u> by feet of investment in each category.

Account 368 – Line Transformers

- Determine zero intercept of transformer cost using cost per transformer by type, <u>*weighted*</u> by number for each category.

(NARUC's *Electric Utility Cost Allocation Manual*, January, 1992, pp. 93-94. Emphasis supplied.)

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.*

A recent text book on electric ratemaking written by Lawrence J. Vogt, P.E. titled *Electric Pricing: Engineering Principles and Methodologies* (CRC Press, Taylor & Francis Group, 2009) also explains that a weighted regression analysis must be used in the application of the zero intercept methodology. Mr. Vogt states as follows:

> The *minimum intercept* or *zero-intercept methodology* provides a rational basis for separating the cost of a device between its customer and demand components. <u>*The zero-intercept methodology is a weighted linear regression*</u> of the unit costs of standard ratings or sizes of a specific device, such as a single-phase overhead line transformer, plotted as a function of its capacity characteristic, which would be kVA for a line transformer. The objective of the regression analysis is to determine the y-intercept. The y-intercept represents that portion of a device's total cost that is associated with zero capacity and thus the customer-related component. <u>*The unit costs must be weighted by the numbers of devices because of the uneven distribution of the various ratings or sizes of the devices in service*</u>.
>
> (Lawrence J. Vogt, P.E., *Electricity Pricing: Engineering Principles and Methodologies*, p. 500. Emphasis supplied.)

Furthermore, I can say with 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 arithmetic 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 this 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 arithmetic exercise" 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.[3]

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

[3] See NARUC's *Electric Utility Cost Allocation Manual*, January, 1992, pp. 93-94.

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 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:[4]

[4] 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 4.

Q. **Do these parameter estimates represent accurate estimates of the linear 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.[5] 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. Watkins' 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

[5] 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 5.

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 6.

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. Do you have any comments concerning Mr. Watkins' proposal to use the ampacity of overhead and underground cable rather than the cross-sectional size of the cable?

A. Yes. The use of ampacity is not a standard approach in the industry. For example, the instructions in NARUC's *Electric Utility Cost Allocation Manual* state that the minimum intercept of conductor is determined "using cost per foot by size and type of conductor weighted by feet or investment in each category." The *Electric Utility Cost Allocation Manual* does not specify the use of ampacity. A major problem with using ampacity is that it is not a fixed quantity for any particular conductor. As stated in T. A. Short, *Electric Power Distribution Handbook* (CRC Press: 2004), "A given conductor has several ampacities depending on its application and the assumptions used." (See pp.61-63). The ampacity of a conductor is affected by cable design, ambient temperature change, sunlight, and wind speeds. Thus, ampacity introduces greater variability into the analysis, relative to using conductor size. This is suggested by the low R-Squares from the regression analysis used by Mr. Watkins to develop his zero intercept estimates for overhead conductor. Specifically, his non-weighted regression analysis using ampacities yields an R-square of only 0.59052 for overhead conductor compared to 0.9053 in the Company's weighted regression analysis. Most power system engineers with whom I have discussed the matter maintain that because of variations in ampacity for different types of conductor, it is more appropriate to use the cross sectional area of the conductor rather than the ampacity in a zero intercept analysis. The use of ampacity should not be adopted until it is recognized as a standard within the industry or until an engineering study is submitted in support of the use of ampacity in connection with a minimum intercept analysis.

Q. On page 27 of his testimony, Mr. Watkins says that he "used Mr. Seelye's 21 categories of LG&E's various sizes and types of overhead conductor." Did he use the same 21 categories of sizes and types of overhead conductor or did he delete a large number of sizes and types of conductor?

A. He deleted numerous data points. In the regression analysis shown on page 1 of Schedule GAW-3, he deleted #12 conductor, #8 conductor, 350 MCM conductor, 556 MCM overhead conductor, 750 MCM conductor, 954 MCM conductor, and 1000 MCM conductor. Therefore, he deleted seven of the 21 categories of overhead conductor used in my analysis, or 33% of the data points. In his regression analysis for underground conductor shown on page 2 of Schedule GAW-3, Mr. Watkins deleted #4 copper conductor, 3/0 copper conductor, 200 MCM copper conductor, and 500 MCM copper conductor. Thus, he deleted four of the 13 categories of underground conductor, or approximately 31% of the data points. On page 27 of his testimony Mr. Watkins states, "While I have used Mr. Seelye's 21 categories of LG&E various sizes and types of overhead conductors." Yet, at the top of Schedule GAW-3 a note states, "Exclude small Quantities". He fails to provide statistical support for the criteria used to drop these data points from his analysis. Presumably, he is attempting to account for the large differences in the quantities of various conductor sizes by arbitrarily deleting approximately one third of the data points. Removing a large number of data points without any explanation lacks rigor. The standard statistical methodology for accounting for differences in quantity is not to toss out a large number of data points but to use a weighted regression analysis.

D. TREATMENT OF CURTAILABLE CREDITS IN THE COST OF SERVICE STUDY

Q. Mr. Baron makes an adjustment to the pro-forma rates of return in the cost of service study to reflect *actual* as opposed to *proposed* interruptible credits under the Curtailable Service Rider. Do you disagree with Mr. Baron's approach?

A. No, particularly if the results of the cost of service study are used in a formulaic manner to reduce class subsidies in the allocation of the revenue increase, as recommended by Mr. Baron for KU. Although Mr. Baron makes the same recommendation for both LG&E and KU, the impact of his adjustment is much evident in the allocation of the revenue increase for KU. In developing his recommended allocation of the revenue increase for KU, Mr. Baron proposes to reduce subsidies by 25%. If this recommendation is approved by the Commission, then Mr. Baron's approach, which produces a significantly lower rate of return for Fluctuating Load Service on the KU system, represents a reasonable basis for calculating class subsidies. Particularly, if subsidies are reduced by 25%, as recommended by Mr. Baron, or even a smaller percentage, then his approach provides a reasonable starting point for allocating the increase to Fluctuating Load Service, which has a large amount of curtailable load.

E. ALLOCATION OF THE ELECTRIC REVENUE INCREASE

Q. Earlier, you mentioned that there was no agreement among the intervenor witnesses regarding the electric cost of service methodology. Is there agreement among them on how the increase should be allocated to the rate classes?

A. No. Primarily because of the atypical load patterns during the test year and the consequent atypical class rates of return produced by the electric cost of service study, the Company proposed to increase all electric rates by the same percentage. Mr. Watkins found the Company's proposed class revenue distribution to be reasonable, while Mr. Baron maintains that too much of the revenue increase is being allocated to the large commercial and industrial rate classes. Based on a proposed overall increase of 12.11%, Mr. Baron would increase the large commercial and industrial rates by 10.22% and the other rates by 12.72%. Because of the unusual load patterns during the test year, Mr. Baron recommends that the Commission rely on the results of the cost of service study from LG&E's previous base rate case for guidance in allocating the revenue increase to the rate classes.

Q. Do you have any objections to Mr. Baron's proposal to rely on the previous cost of service as a guide for allocating the increase in this proceeding?

A. Because of the impact of the unusual load patterns during the test year of this rate case proceeding, the Company proposed the same percentage increase for each rate class. Without preparing another cost of service study based on some future test year, it is not possible to substantiate Mr. Baron's opinion that the cost of service study from the previous rate case is more appropriate on a going-forward basis than the one submitted in this proceeding. Nevertheless, I agree with Mr. Baron that the class rates of return from the previous cost of service study may be more representative on a going forward basis than those determined from the cost of service study developed using actual test-year data in this proceeding should the trend toward greater load growth not be sustained. However, relying on the results of the previous cost of service study to set rates is not without problems, not the least of which is that to my knowledge there is no precedent for falling back to an earlier cost of service study for setting rates and lends itself to picking cost of service studies that simply produce the result one constituency group or another desires. I do not have a strong objection to Mr. Baron's proposal, but this approach represents a new direction best left to the sound discretion of the Commission.

III. ELECTRIC RATE DESIGN

A. BASIC SERVICE CHARGE

Q. Is the Company proposing to move the basic service charges closer to the actual cost of service?

A. Yes. It has been a longstanding goal of the Company to move basic service charges (formerly called "customer charges") more in line with the actual cost of service. Because of the infrequency of rate case filings by the Company and because a number of base rate changes over the last 20 years have resulted in decreases, it has been difficult for the Company to make much progress in this area. In the settlement submitted in Case No. 2003-00433, the parties agreed to basically double the basic service charge. In the settlement in the previous rate case (Case No. 2008-00252), the parties agreed to maintain the basic service charge at the same level even though the case resulted in a revenue decrease. Therefore, in both of these proceedings some progress was made to move the basic service charge more in line with cost of service. However, not nearly enough movement has been made in this direction. The basic customer cost of serving a residential customer is $15.80 per month, whereas the Company's basic service charge is currently $5.00 per month. Thus, $10.80 per customer per month in customer-related fixed distribution costs are being recovered through a volumetric kWh charge rather than through the basic service charge where these costs should be collected. This violates the basic ratemaking principle of collecting fixed costs through fixed charges and variable costs through variable charges. When this principle is violated, it results in intra-class subsidies, as is the case here where customers with above average usage are paying more than their fair share of customer-related fixed distribution costs and customers with below average usage are paying less than their fair share of customer-related fixed distribution costs and are being subsidized. When the cost of service is not followed, customers are provided inaccurate price signals which encourage them to make incorrect decisions about energy efficiency. The residential basic service charge is currently less than 32 percent of the actual cost of providing service. I am unaware of any other charge billed by LG&E that is this far out of line with the actual cost of providing service.

Q. What does Mr. Watkins' own cost of service study indicate that the basic service charge should be?

A. Mr. Watkins' own cost of service study indicates that the residential basic service charge should be $11.26 per month. Even though Mr. Watkins claims that LG&E's monthly residential customer cost is only $3.58 per month, he gets there by ignoring the results of his own cost of service study. In his 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 calculates his proposed basic service charge. Specifically, he only includes costs associated with services, meters, meter reading, and records and collections in the calculation of his proposed basic service charge, ignoring costs associated with poles, overhead conductor, underground conductor, transformers and certain administrative and general expenses[6] that were classified as customer-related in his own cost of service study. Furthermore, Mr. Watkins provides no sound rationale or basis for this omission. 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 basic service charge:

[6] 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 BASIC SERVICE 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 Accounts Expenses (Account 905)	Yes	*No*
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 basic service 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 GAW-9, he includes an item that was not even classified as a customer-related cost 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 GAW-9, Mr. Watkins calculates a residential basic service charge of only $3.58 per month. Seelye Rebuttal Exhibit 7 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 $11.26 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 basic service charges. Just as Mr. Watkins has done in the current proceeding, the AG's cost of service witness proposed a basic service 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 and should do the same in this proceeding.

Q. Do you have any other comments regarding the basic service charge recommended by Mr. Watkins?

A. Yes. Even though he claims that his study can only support a $3.58 basic service charge, he recommends a basic service charge of $5.00, the current level. Mr. Watkins is joined by AARP witness Brockway in recommending no increase in the residential basic service charge. LG&E's cost of service study would support a basic service charge of $15.80. LG&E's proposed basic service charge more accurately reflects the cost of providing service than Mr. Watkins' proposal. Ms. Brockway fails to present any type of quantitative analysis – such as cost support or customer impact analysis – in support of her recommendation. Without offering any empirical data or cost analysis whatsoever, Ms. Brockway recites a well-worn and unsupported list of criticisms against higher basic service charges, which originated from the 1970s but are now largely rejected by some of the more progressive advocates for improving energy efficiency – "higher customer charges discourage conservation"; "higher customer charges harm low income customers"; "utilities with higher customer charges should be penalized with lower rates of return".

Mr. Watkins and Ms. Brockway's proposal 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. The basic service charge basically covers the minimum amount of equipment necessary to provide a customer with grid access, and an artificially low basic service charge sends the incorrect price signal that this minimum amount of equipment is relatively inexpensive. Their proposal would increase the volatility in customer bills by collecting too much customer-related fixed distribution cost during peak months and during periods of extreme weather while collecting too little during periods of mild weather. This has the undesirable effect of unnecessarily increasing the volatility of customer energy bills, with the high bills higher than necessary and the low bills lower than necessary. Likewise, their proposal would increase the Company's revenue volatility.

Their 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. Mr. Watkins and Ms. Brockway's proposal would further penalize these customers by charging them an average rate that moves further away from the cost of providing service.

Furthermore, Mr. Watkins and Ms. Brockway's 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 assessed on a kWh basis rather than a fixed monthly basic service 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. Many 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. Mr. Watkins and Ms. Brockway's regressive recommendation would take us back to the failed approaches of the 1970s, when the accepted 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 progressive rate design philosophies that create a win/win for both the customer and the utility 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) and implementing smart energy technologies with low-power sensor networks using IEEE 802.15.4 MAC protocols or Zigbee architectures.

Q. Ms. Brockway and Mr. Buechel oppose the proposed increases in the basic service charges because of "rate continuity" and "gradualism". Do they have valid arguments?

A. No. Citing the ratemaking principle of "rate continuity", Ms. Brockway recommends that the basic service charge for residential service remain unchanged at $5.00 per month. She offers no cost support for her recommendation. Without offering any evidence in support of her assertion, she maintains that increasing the basic service charge will not benefit low-income customers, even though recent empirical evidence has been submitted to the contrary. As described in my direct testimony, in 2008 LG&E collected sales data for residential customers who met the State standards for participating in low income energy assistance programs ("LIHEAP"). Based on that data, the average monthly usage for LIHEAP customers was 1,084 kWh, compared to 1,066 kWh per month for an average residential customer. Hence, the typical LIHEAP customer would actually benefit from a rate design with a higher basic service charge. Ms. Brockway fails to offer the single piece of empirical evidence – either in the form of cost support or actual customer impacts – to support her recommendation.

Similarly, Mr. Buechel expresses concern about the proposed increases in the basic service charges for General Service - Rate GS, Power Service - PS, Commercial Time-of-Day Secondary Service - Rate CTODS, and Commercial Time-of-Day Primary Service - Rate CTODP. Like Ms. Brockway, Mr. Buechel does not feel that the increases are gradual enough. Also like Ms. Brockway, he fails to provide a single piece of empirical evidence – either in the form of cost support or actual customer impacts – to support his vague notion that the basic service charges are not gradual enough. Neither Mr. Buechel nor Ms. Brockway try to explain why – and under what circumstances – the principles of "gradualism" and "rate continuity" should take priority over the principle of "cost of service", which is also identified in the Bonbright treatise cited by Ms. Brockway. As the late professor Bonbright stated, "Without doubt the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service." (James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press: 1961; p. 294.) In fact, rate continuity is not listed as one of the three "primary" objectives identified by professor Bonbright – (i) revenue requirement objective, (ii) cost apportionment objective, and (iii) economic efficiency objective. (*Id.*, at p. 292.)

Ultimately, Ms. Brockway and Mr. Buechel's vague and opaque notions of "gradualism" and "rate continuity" are too imprecise to be of any use as a regulatory guideline for setting rates. For example, Mr. Buechel does not recommend a specific basic service charge, and he fails to specify the point where a specific increase in the basic service charge is no longer "gradual". Apparently, Ms. Brockway's concept of "rate continuity" for the basic service charge is no increase at all. But like Mr. Buechel, she fails to identify the point where an increase in a particular component of a rate begins to violate the principle of "continuity". The issue that both Mr. Buechel and Ms. Brockway obscure is that, with respect to the principles of "gradualism" and "rate continuity", the impact on the total bill has far more significance than the impact of particular components of a rate. Neither of them has produced empirical evidence demonstrating that the Company's proposed increase in the basic service charge will result in any greater hardship for actual customers than continuing to recover customer-related costs through the energy charge.

B. CURTAILABLE SERVICE RIDER

Q. Please briefly summarize the proposed changes to the Company's curtailable service riders.

A. The Company currently has three CSR riders – CSR1, CSR2 and CSR3 – which evolved from negotiated settlements in LG&E and KU's last two rate cases. Two LG&E customers and one KU customer currently take service under CSR1, and one KU customer takes service under CSR3. The Company is proposing to consolidate these three curtailable service riders into a single rider, which will be called Curtailable Service Rider CSR. The Rider will provide up to 500 hours of total curtailment and will provide credits consistent with CSR1. Under the proposed CSR, the Company will have the right to request up to 100 hours of physical curtailment without buy-through and up to 400 hours of curtailment with a buy-through option, where the customer can choose to either curtail its load or purchase buy-through power. This structure was presented to the Company by its customers. The buy-through power will be priced at an automatic, formula-based price determined by multiplying an indexed cost of natural gas ($/MMBtu) by a specified heat rate (.01200 MMBtu/kWh) representative of the heat rate of a typical single-cycle combustion turbine. The Company will provide at least a 10 minute notice prior to curtailment.

Importantly, under the proposed CSR, the credit will only be applied during periods of the day when the Company is likely to need curtailable service. Specifically, the credit will be applied to the difference between (a) the Customer's measured maximum kilowatt demand during any 15-minute interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M., and (ii) for the months October continuously through April,[7] from 6 A.M. to 10 P.M., and (b) the firm contract demand. This is arguably the most significant change that the Company is proposing. Under the proposed CSR the Company may request or cancel curtailment at any time during any hour of the year despite the periods used to calculate the demand credit.

Q. Why is the Company proposing to consolidate the three riders into a single tariff?

A. The current structure of having three curtailable service riders is difficult for the Company to manage from an operational perspective, particularly since the terms and conditions of the three tariffs are not consistent with one another. Under CSR3, the customer must curtail its load whenever the Company issues a request for curtailment. However, the Company can only request 100 hours of curtailment during any 12 month period. CSR1, however, currently does not include a provision that requires the customer to physically curtail its load. Under the current CSR2, the customer can choose either to curtail its load or request that the Company go into the market to buy power to serve the load. The Company needs to have the ability to call on its curtailable customers to physically interrupt their loads in order for this resource to have value for the Company in the planning process and for avoiding future capacity additions. During certain conditions, including emergencies, it is

[7] It should be noted that there is a typographical error in the proposed tariff sheets for CSR included in Tab 7 and Tab 8 of the Statutory Notice, Application, Financial Exhibit, Table of Contents, Filing Requirements filed on January 29, 2010. On Original Sheet No. 50.1, in the section "Curtailable Billing Demand", under small Roman numeral (iii), the non-summer months should be listed as "October continuously through April" instead of "October continuously through May".

important for the Company to be able to call on these customers – to which it is paying a hefty capacity credit of $5.10 to $5.20 per kW per month – to physically curtail their load. Currently, there are far less costly options for obtaining capacity than providing curtailable customers a $5.10 to $5.20 per kW monthly credit. The Company can currently purchase capacity at a far lower cost than is currently being "paid" to its curtailable customers for the right to buy-through on their behalf without the ability to require them to actually reduce their loads. The Company proposes to include a provision in its curtailable service rider that provides up to 100 hours of physical curtailment during any 12 month period.

Q. KIUC witness Dennis W. Goins makes a number of specific recommendations concerning the Company's proposed tariffs. He proposes that LG&E offer a CSR10 with ten minutes notice and CSR30 with 30 minutes notice. Do you have any general comments regarding CSR10 and CSR30?

A. Yes. Mr. Goins and I are not too far apart on a number of issues. We both agree that curtailable service provides economic benefits to the Company and its customers. Mr. Goins recommends that both CSR10 and CSR30 be subject to a total of 100 hours of physical interruption. Also, at least provisionally, he does not object to the adoption of LG&E's proposed formula-based methodology for pricing buy-through power. Furthermore, we are not too far apart on the maximum level of the curtailable credit that should be offered. Although, Mr. Goins acknowledges, but offers no criticism concerning, the Company's proposed change in the period during which curtailable demand is determined, I assume that we are also in agreement on this point.

Q. Mr. Goins recommends that if the Company's formula-based buy-through pricing approach is approved by the Commission, then it should be reviewed and evaluated in a future case to determine if it produces reasonable and fair results. Do you agree with this recommendation?

A. Yes. I agree that it would be reasonable to re-examine the buy-through pricing approach in a future case to determine if it produces fair and reasonable results. In proposing this approach, the Company is attempting to simplify the buy-through process, on behalf of both the Company and its customers. Purchasing buy-through power is time consuming and difficult to accomplish, especially in terms of purchasing the correct amount of buy-through power. Eliminating the need to contract for each buy-through transaction through the application of the proposed formula-based pricing should greatly simplify the process. However, it will be prudent to review the approach as a part of a future rate case proceeding. Curtailable service has been carefully scrutinized by all of the affected parties in the last several rate cases. Because of its importance to the Company and its customers, I do not anticipate this situation to change in the future and fully expect that the buy-through pricing formula and other aspects of the tariff will be reviewed in the Company's next rate case.

Q. Do you have any objections to Mr. Goins' methodology for determining the amount of buy-through energy determined under CSR?

A. No. Mr. Goins proposes to determine the amount of energy priced under the automatic buy-through formula rate to be determined by subtracting (i) the customer's firm demand multiplied by the number of hours (or fractional number of hours) of curtailment from (ii) the customer's actual energy use during the curtailment period. This approach is reasonable.

Q. Do you have any objection to Mr. Goins' recommendation to place a limit on the availability of curtailable service to the current MW of CSR1 and CSR3 curtailable load plus an additional 100 MW?

A. No. I believe that there should be some sort of limitation on the addition of new load under the curtailable service riders. Mr. Goins recommendation to allow only 100 MW of additional curtailable load above the current curtailable load of customers served under CSR1, CSR2, and CSR3 is reasonable.

Q. Do you agree with Mr. Goins' proposal to provide a credit of $5.40 and $5.50 per kW-month for primary and transmission curtailable service under CSR10 and with his proposal to limit the maximum hours of curtailment to 350 hours?

A. No. I continue to maintain that a credit of $5.10 and $5.20 per kW-month for transmission and primary curtailable service with 500 annual hours of curtailment is reasonable in the power market environment today. The Company can currently purchase capacity in the market at a delivered price that is far less than $5.10 per kW-month. Although the market price of capacity may turn around, the issue can be re-examined in LG&E's next rate case. Ultimately, Mr. Goins and I are not too far apart on the level of the credit that should be provided. The more critical issue is the total number of hours of curtailment during a 12 month period. Again, I continue to maintain that it is reasonable to require curtailable service customers to curtail their load for up to 500 hours during a 12 month period in exchange for a fairly robust curtailable credit – or at least robust in today's power market.

Q. Do you have any comments concerning Mr. Goins' proposal to allow customers to avoid noncompliance penalties if the customer agrees to install, pay for, and cede to LG&E control of the equipment necessary to curtail the customers' load in excess of the firm demand?

A. Yes. The Company is willing to work with its curtailable customers to install the necessary telecommunication and control equipment to allow the Company to control customers' curtailable load as long as the Company's and the customer's individual responsibilities are clearly defined and the customer pays for the necessary equipment. Furthermore, the Company is willing to waive the non-compliance charge if the *Company's* telecommunication and control equipment, which will need to be fully isolated from the customer's telecommunication and control equipment, fails to send the necessary control signals to curtail the customer's load. However, the Company is not willing to waive the non-compliance charge if a failure of the *Customer's* telecommunication and control or other equipment results in the load not being curtailed. It is not reasonable to require LG&E to take responsibility of telecommunication and control equipment within the customer's manufacturing facilities or of equipment that is owned, operated, maintained, and controlled by the customer.

Additionally, if an arrangement is made to install telecommunication and control equipment to control the customer's curtailable load, then backup arrangements must be established in the event that either the Company's or the customer's telecommunication and control equipment fails. Such backup arrangements would require guaranteed telephone access to an operator at the customer's facilities so that the customer can be notified of a request to curtail the load. In other words, if the Company sends an electronic signal to curtail the customer's curtailable load and if the load is not curtailed due to either a failure of the Company's telecommunication and control equipment or a failure of the customer's telecommunication and control or other equipment, the Company may, but is not required to, contact the customer by telephone and make an oral request for curtailment. If a failure of the customer's telecommunication and control equipment resulted in the load not being curtailed originally, then the customer would be responsible for paying any non-compliance charges as of the time of the initial electronic request. However, if a failure of the Company's telecommunication and control equipment resulted in the load not being curtailed, then a non-compliance charge would not be charged. If the Company exercises its option to call and if the customer fails to answer the dedicated phone line, or if the dedicated phone line rolls over to voice mail, and the customer does not curtail its load upon being provided a 10 minute notice, then a non-compliance charge would be applied based on the time 10 minutes after the initiation of the telephone call. The customer's dedicated phone line must have voice mail capability.

Q. **Do you have any objection to Mr. Goins' proposal for LG&E to provide a good faith estimate of a curtailment's estimated duration when LG&E issues a curtailment notice?**

A. No. However, if the Commission accepts this modification then there should be a reciprocal obligation for the customer to provide a good faith estimate of its production schedules. Both estimates should be non-binding. It must be noted that at all times the Company must have detailed knowledge about the availability of all of its generation resources, including its combustion turbines. If LG&E is to rely on curtailable load as a resource, it is equally important that the Company also have detailed knowledge about the availability of curtailable load on its system.

Q. Do you have any objection to Mr. Goins' proposal for LG&E to offer a CSR30 that requires the Company to provide customers served under the rider a 30 minute notice?

A. No. However, I believe that the credit should be significantly lower than the credit provided for CSR10, which would only require 10 minutes notice. The ability to call on a customer to curtail load within 10 minutes is of great value to the Company, especially during emergencies. If the customer is to receive a curtailable credit approximately equal to the avoided capacity cost of a quick-start combustion turbine, then the Company should be able to curtail the load within 10 minutes, which is the maximum amount of time that it takes to synchronize a quick-start combustion turbine to the grid. In my opinion, the credit for CSR30 should not exceed 60% of the credit for CSR10. Therefore, if the credit for CSR10 is $5.10 and $5.20 per kW-Month for transmission and primary service, the credit for CSR30 should not exceed $3.06 and $3.12 per kW-Month.

C. FLUCTUATING LOAD SERVICE

Q. Please describe the changes that the Company is proposing to the Fluctuating Load Service.

A. The Company is proposing to simplify Fluctuating Load Service (currently called "Industrial Service IS") by implementing the time-of-day rate structure similar to the structure being proposed for the Company's standard time-of-day rates applicable to large industrial and commercial customers, but with demands determined on a 5-minute integrated demand basis. As in all of the Company's other proposed larger power rate schedules -- Industrial Time-of-Day Secondary Service – ITODS, Commercial Time-of-Day Secondary Service – CTODS, Industrial Time-of-Day Primary Service – ITODP, Commercial Time-of-Day Primary Service – CTODP, and Retail Transmission Service – RTS – the Company is proposing a 75% demand ratchet applicable to the Base demand charge and a 60% demand ratchet applicable to the Peak and Intermediate demand charges. With a demand ratchet, the billing demand for the current month reflects the higher of (i) the maximum demand during the month, or (ii) the highest demand during the previous 11 months multiplied by the ratchet percentage. Demand ratchets of between 50 to 75% are common throughout the United States for large power rate schedules.

Q. What is the purpose of having a demand ratchet?

A. Demand ratchets help ensure the recovery of the fixed costs of facilities installed to meet the customer's maximum demand. They also allow the utility to recover some of the stranded fixed costs incurred by the Company when an industrial or commercial customer shuts down its operations. Much like a basic service charge, demand ratchets help stabilize a utility's revenue from one month to another. Perhaps most importantly, demand ratchets encourage customers to maintain high annual load factors. Ratchets reward customers that maintain high annual load factors, penalize customers that have low annual load factors, and help eliminate intra-class subsidies. Although they help stabilize monthly billings, demand ratchets do not alter the revenue requirement collected from any particular rate class. With or without demand ratchets, the test-year revenues collected are the same. While they do not affect the overall test-year revenue collected from a particular class, demand ratchets do have varying impacts on individual customers within a particular rate schedule. Specifically, when demand ratchets are in place, customers with high annual load factors (i.e. customers whose loads are relatively flat throughout the year) will pay a lower average charge than Customers whose demands vary significantly from one month to another. Consequently, demand ratchets provide a powerful incentive for customers to improve their annual load factors and thus utilize installed generation, transmission and distribution capacity more efficiently.

Q. Do you agree with Mr. Baron's recommendation to reduce the demand ratchet for Fluctuating Load Service?

A. No. In fact, I am more than a little puzzled by his recommendation. On the one hand, Mr. Baron criticizes the Company's cost of service study because it allocates too much fixed production and transmission costs to high load factor customers (see Direct Testimony of Stephen J. Baron, page 5, lines 4-7), but he objects to the implementation of a demand ratchet, which is a powerful ratemaking mechanism designed to reward customers that maintain high load factors. His two positions cannot be reconciled. It is also important to note that Mr. Baron does not object to the implementation of a demand ratchet for Industrial Time-of-Day Secondary Service – ITODS, Industrial Time-of-Day Primary Service – ITODP, and Retail Transmission Service – RTS, under which a number of *high load factor* KIUC members take service. As I mentioned earlier, customers with high annual load factors, such as large chemical plants and manufacturing facilities that operate around the clock, tend to benefit from the implementation of a demand ratchet.

D. CONJUNCTIVE DEMAND

Q. Does LG&E object to implementing conjunctive demand billing?

A. No. As stated in my direct testimony, LG&E does not object to conjunctive demand billing as long as it is implemented in a cost-based and equitable manner and as long as customers under a properly design conjunctive demand rate reimburse the Company for any additional metering, billing and other administrative costs involved in providing the service. Additionally, as with all rates, any conjunctive billing rate must be applied and billed the same way that it is calculated. A properly structured conjunctive demand rate would consist of a distribution and transmission demand charge that would be applied to the customer's maximum demand at each delivery point and production demand charge that would be applied to the customer's demand determined either on an aggregated or individual customer basis at the time of the Company's system peak. In other words, the distribution and transmission demand charge would be calculated and billed on the basis of the customer's non-coincident peak demands (maximum individual demand) and the production demand charge would be calculated and billed on a coincident peak basis. A conjunctive demand rate designed and applied in this manner would be cost-based and would not be inherently preferential to a customer that has multiple stores, warehouses, schools, or factories operating in the Company's service territory.

Q. Why is the conjunctive demand rate that you describe "cost based"?

A. In the Company's cost of service study, peak and intermediate period generation demand costs are allocated to the customer classes on the basis of each customer class's demand at the time of the Company's system peak. In other words, the Company's fixed production costs are driven by coincident peak demands. In the cost of service study, most distribution costs are assigned on the basis of a non-coincident peak allocator. Therefore, a conjunctive demand rate that recovers production costs through a coincident peak charge and recovers distribution costs through a non-coincident peak charge closely mirrors the way that costs are allocated in the cost of service study.

Q. Why is the conjunctive demand rate that you describe not inherently preferential?

A. A conjunctive demand rate designed and applied in the manner as described above would result in the same billings regardless of whether the charges are applied on an aggregated or individual, unaggregated basis. In other words, a coincident peak demand charge calculated and applied to the aggregated (or totalized) loads for multiple service locations will produce the same total demand billings as a coincident peak demand charge applied individually to the loads for multiple service locations, added together. Consequently, there is no inherent advantage for applying a coincident peak to the aggregated demands of multiple store, warehouse, school, or factory locations.

Q. Is the conjunctive demand rate proposed by Kroger witness Neal Townsend inherently preferential?

A. Yes. Mr. Townsend proposes that a conjunctive demand rate be developed that would apply a production demand charge to the maximum aggregated demands of multi-site businesses or entities. Under such a rate structure, businesses such as Kroger that have multiple stores operating in the Company's service territory would automatically realize a billing reduction compared to non-multi-site businesses. Simply by aggregating their demands, Kroger and any other entity with multi-site accounts operating in the Company's service territory would automatically realize a bill reduction in relation to other customers without any change to their operation or change in their consumption of electric energy or demand. In virtually all real world situations, the maximum monthly demand of the aggregated loads of multiple accounts will be less than the sum of the maximum demands of the individual loads of multiple accounts. This is equivalent to the following mathematical expression:

$$\max_j \sum_{i=n}^{n} Load_{ij} \leq \sum_{i=1}^{n} \max_j \{Load_{ij}\}$$

where $Load_{ij}$ refers to load of customer i during the 15-minute interval j, and n refers to the total number of customers being aggregated. The expression on the right hand side of the greater than or equal sign (≤) corresponds to the current way that generation billing demand would be determined for multi-site customers. The expression on the left hand side of the greater than or equal sign corresponds to the way that Mr. Townsend proposes that the generation billing demand for multi-site customers would be determined. Therefore, Mr. Townsend's proposal will almost certainly result in an automatic windfall to Kroger and other multi-site businesses without encouraging them to do anything to operate more efficiently.

The above mathematical principle can be illustrated numerically by adding the individual maximum values of two randomly generated series of numbers -- Series A and Series B -- between 0 and 100, and then comparing the sum of these two maximum values to the maximum value of the series determined by adding (aggregating) each element of Series A and Series B. No matter how many times different sets of random numbers are generated, the maximum value of the series determined by adding each element of Series A and Series B will be less than the sum of the maximum value of Series A plus the maximum value of Series B. This is illustrated in Seelye Rebuttal Exhibit 8. This exhibit shows that the maximum value of the randomly generated Series A is 99 and the maximum value of the randomly generated Series B is 95. The sum of these two maximum values is therefore 194. But the maximum value of the aggregated series determined by adding each element of Series A to the corresponding element of Series B is only 167. Therefore, on a purely random basis, aggregation results in a lower maximum value.

Q. Do you have a real world example where the demands of two multi-site customers are aggregated?

A. Yes. Seelye Rebuttal Exhibit 9 shows the effect of aggregating the actual 15-minute demands of two multi-site stores during January 2010. The maximum 15-minute demand of Customer A during the month is 461 kW. The maximum 15-minute demand of Customer B during the month is 2,246 kW. The total of the two maximum demands for the two stores is 2,707 kW. When the 15-minute demands for the two stores are aggregated, the maximum aggregated demands of the two stores is 2,638 kW. Therefore, aggregation results in a demand savings of 69 kW per month. Of course, increasing the number of accounts that are aggregated would increase the savings. It is important to point out that these demand savings are realized without the customer taking any action to manage their loads in a more efficient manner.

Q. Mr. Townsend indicates that conjunctive demand billing has been adopted in Michigan on a pilot basis by Detroit Edison and Consumers Energy. Do you have any comments about the Michigan pilot programs?

A. Yes. The economic and regulatory environment in Michigan is quite different than in Kentucky. Detroit, in particular, is one of the most economically-distressed urban areas in the United States. More importantly, Michigan is a "retail access" or "customer choice" state, which means that customers can choose to purchase generation service from a competitive supplier. Therefore, the economic and regulatory environment in Michigan is in no way comparable to the economic and regulatory environment in Kentucky. For Detroit Edison, the "Experimental Load Aggregation Provision" was authorized as a part of a Stipulation Agreement in Case No. U-14838 which was approved by the Michigan Public Service Commission on August 31, 2006. For Consumers Energy, the "Aggregate Peak Demand Provision," which was modeled after the provision set forth in the Detroit Edison Stipulation, was approved by the Michigan Public Service Commission in an Order in Case No. U-

15245 dated June 10, 2008. Consumers Energy's Aggregate Peak Demand Provision was not opposed by any party in that proceeding and was supported by Kroger. Testimony in support of Consumer Energy's pilot submitted by Kroger witness Kevin C Higgins in Case No. U-15245 underscores the connection between the competitive environment for electric power in Michigan and the adoption of the pilot:

> The GAP pilot would allow a customer taking service under the General Primary Demand ("GPD") or General Secondary Demand ("GSD") rate schedule with multiple accounts to aggregate its loads for the purpose of determining its monthly peak demand for power supply service. This type of aggregation would allow the customer to capture the diversity within its loads for billing purposes. For example, a customer may have multiple accounts that experience peak demands at different times. Currently, the customer is billed for power supply demand based on each individual account's peak demand during the month. The GAP program would instead bill the customer for power supply demand based on the customer's peak demand for its aggregated load. ***This approach is comparable to how the customer's load would be viewed by a competitive supplier***. (Direct Testimony of Kevin C. Higgins on behalf of The Kroger Co., November 6, 2007, p. 4. Emphasis supplied.)

Because retail competition for electric power is allowed in Michigan, the aggregated billing programs adopted by Detroit Edison and Consumers Energy have little or no relevance to LG&E, which operates in a traditional, regulated environment..

Q. Do you believe that LG&E met its obligation under the settlement agreement to study conjunctive demand billing?

A. Yes. Although it has not developed a rate that will provide an automatic benefit to Kroger and other multi-site businesses, I believe that the Company has met its obligation under the settlement agreement in the Company's last rate case to study conjunctive demand billing.

Q. Do you agree with Mr. Townsend's recommendation that the Commission require LG&E to establish a pilot program to test the efficacy of measuring the generation demand for multi-site customers on a conjunctive demand basis?

A. LG&E does not have any objection to establishing a pilot program to study conjunctive demand billing as long as the generation demand component of the rate is developed on a revenue neutral basis and billed as a coincident peak demand charge. The Company must also recover from program participants any incremental metering and administrative costs for conducting the pilot program. However, the Company does not agree that it would be appropriate to develop a pilot program in which the generation demand component is simply applied to the maximum 15-minute aggregated demands of multi-site customers. Thus, it is unlikely that the Company will be able agree that Mr. Townsend's version of conjunctive demand billing is appropriate.

E. KVA DEMAND BILLING

Q. Please briefly explain why LG&E is proposing to bill primary voltage customers taking service under ITOD-P on a kVA basis?

A. As explained in my direct testimony, a kVA charge does a better job of reflecting the cost of providing service to primary and transmission voltage customers. The Company's proposal is a continuation of the transition to kVA billing for large voltage customers that was begun in the Company's last rate case. In the rates approved in Case No. 2008-00252, LG&E and KU began billing transmission voltage customers on a kVA basis. The proposal to adopt kVA billing for both LG&E and KU is also a key element in the effort to harmonize the tariffs of the two Companies. The power factor provision included in KU's large power rate schedules is much closer to kVA billing than the power factor provision included in LG&E's large power rate schedule. Implementing kVA billing for both utilities will simplify the Companies' billing operations and also will help alleviate customer and employee confusion regarding LG&E and KU's service schedules.

Q. Please describe Mr. Baron's recommendations regarding kVA billing?

A. As he explains in his testimony, Mr. Baron does not oppose the shift to kVA billing on a conceptual basis. Furthermore, he is not recommending against implementing kVA billing for KU. His opposition to kVA billing relates to LG&E's large power customers. Mr. Baron observes that moving to kVA billing has a greater impact on LG&E's customers, particularly the members of KIUC, than on KU's customers. The reason for this is that KU's power factor provision is determined on the basis of the power factor measured at the time of the maximum demand and is thus much closer in form to a kVA demand charge than LG&E's power factor provision, which is assessed on the basis of average power factor.

Q. Do you agree with Mr. Baron's recommendation that the Commission reject the implementation of kVA billing for LG&E's rate ITOD-P?

A. No. A kVA demand charge sends a more accurate price signal than a kW demand charge. Reactive power ties up generation and transmission capacity, both of which are expensive to construct. The power that the Company delivers to its customers is more accurately represented by kVA demands than by kW demands. Because kW demand represents the real component of power (measured in kW), but not the reactive component of power (measured in kVar), kW billing fails to reflect the actual cost of providing reactive power service. For this reason there is a trend within the industry to adopt kVA billing or to incorporate power factor provisions that result in a billing adjustment if power factor deviates from unity.[8] Mr. Baron is not recommending against the adoption of kVA billing for KU. LG&E does not believe that it is appropriate to adopt kVA billing for KU but not for LG&E. As mentioned earlier, moving to kVA billing is an important element in the effort to harmonize LG&E and KU's tariffs.

Q. Mr. Baron opposes the adoption of kVA billing for LG&E but not for KU because of the impact that the proposed change could potentially have on certain large power customers on LG&E's system. Is this a valid reason for not adopting kVA billing for LG&E?

A. No. Mr. Baron correctly observes that implementing kVA billing will have a greater impact on customers with low power factors than customers with high power factors. Mr. Baron expresses concern that this modification could, in extreme instances, result in billing increases that could potentially be as high as 18-19%. Mr. Baron's concern about the possibility of a small number of *individual* industrial customers served under ITOD-P receiving an increase as high as 18-19% cannot be reconciled with his

[8] A unity power factor is the instance where the measured kW demand is exactly equal to the measured kVA demand, resulting in a power factor of 1.0, where power factor is calculated as follows:

$$Power\ Factor = \frac{kW}{kVA}$$

recommendation to increase rates for the ***entire class*** of residential customers by 19.56% and to increase rates for the ***entire class*** of all-electric school customers by 20.47% on the KU system.

Although this rate modification could have a significant impact on some customers, those customers will almost certainly find it to be economical to install capacitor banks to improve their power factor rather than continue to pay higher demand charges. Therefore, the impact of the higher charges will likely be temporary. LG&E believes that most if not all customers served under ITOD-P and CTOD-P will understand that their power factors can be corrected by installing capacitor banks. These rate schedules are applicable to customers with demands of at least 250 kVA, and many of the customers served under these rate schedules have demands far in excess of this level. Therefore, these are not small customers. They tend to be sophisticated users of electric energy with electrical engineers on their staffs with responsibilities for managing their energy facilities. Furthermore, the Company has made a commitment to contact all customers served under these two rate schedules to review their options for improving their power factor. See response to KPSC 3-22.

IV. GAS COST OF SERVICE AND RATES

A. GAS COST OF SERVICE METHODOLOGY

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. In addition, NARUC's *Gas Distribution Rate Design Manual*, June 1989, identifies the zero intercept approach as a standard methodology for classifying gas distribution costs.[9]

[9] 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."

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 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, the Commission has never approved a cost of service study for LG&E that allocated the cost of distribution mains on the basis of Mcf sales.

B. ALLOCATION OF THE GAS REVENUE INCREASE

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.

C. STRAIGHT FIXED VARIABLE RATE DESIGN

Q. Please describe the Straight Fixed Variable rate design that is being proposed by LG&E for Residential Gas Service - Rate RGS.

A. LG&E is proposing to recover all of its fixed costs through a fixed monthly charge. The Company, however, will continue to recover variable costs – specifically gas supply costs – through a volumetric charge. It is important to note that gas supply costs typically represent anywhere from 60% to 80% of the total cost of serving residential customers, depending on the price of natural gas in the market. Therefore, between 60% and 80% of total costs will continue to be recovered through a volumetric charge (i.e., based on the amount of gas that the customer uses).

Q. Mr. Watkins claims that it is incorrect to characterize the Company's proposed rate as a "straight fixed variable" rate. Is he correct?

A. No, at least not in the context of Straight Fixed Variable Rate design as implemented by local distribution companies (LDCs). The Company is proposing a Straight Fixed Variable rate design in the form that has been implemented by a number of LDCs, including LDCs in neighboring states, Ohio and Missouri. I agree that a straight fixed variable rate design implemented by a gas pipeline will be structured differently than a Straight Fixed Variable rate design implemented by an LDC. Pipelines typically provide transportation and storage service to LDCs and their rates will typically consist of a demand charge and volumetric charge. LDCs, on the other hand, typically provide service to end-use residential, commercial and industrial customers; therefore, LDC rates will typically consist of a basic service charge and a volumetric charge.

Q. Mr. Watkins claims that a Straight Fixed Variable rate design promotes additional consumption. Do you agree?

A. No. Mr. Watkins states that, "[t]hese rate structures promote consumption because the consumers' price of incremental consumption is de minimus, or at the very least, less than what an efficient price structure would otherwise be." (Watkins Direct Testimony, page 43, lines 6-8.) This statement is erroneous. It is incorrect to claim that under a Straight Fixed Variable rate design the "price of incremental consumption is de minimus" when between 60% and 80% of the total cost is recovered through a volumetric charge. Under the Company's proposal, the charge for *incremental consumption* is $5.3494 per Mcf based on the Gas Supply Cost in effect between February through April, 2010. For a customer with average usage of 69.9 Mcf per year, the volumetric charge would result in charges of $374 per year, which is hardly *de minimus*. Nor are the charges "less than what an efficient price structure would otherwise be." From the standpoint of economic efficiency, it is more efficient to recover fixed costs through a fixed charge and variable costs through a variable charge, which is exactly what a Straight Fixed Variable rate design accomplishes. As the Public Utilities Commission of Ohio determined in its Order dated January 7, 2009 in *Vectren Energy Delivery of Ohio, Case No. 07-1080-GA-AIR; Case No. 07-1081-GA-ALT; Case No. 08-632-GA-AAM,* pp. 25-30, a Straight Fixed Variable rate design, "promotes the regulatory principles of providing a more equitable allocation among customers, regardless of usage. It fairly apportions the fixed costs of service among all customers so that everyone pays their fair share" and "sends a better price signal".

Mr. Watkins goes on to make the unsubstantiated and, in fact, incorrect claim that, "FERC's SFV pricing mechanism reduced the price of incremental (additional) natural gas consumption thereby significantly increasing the demand for, and use of, natural gas in the United States subsequent to 1992 (when Order 636 was issued)." FERC's straight-fixed variable approach was designed to ration capacity so that pipeline customers would utilize capacity more efficiently by making those customers pay for the capacity who value it the most and to stop "capacity hoarding". Besides failing to establish a causal relationship between the FERC's adoption of a straight fixed variable rate design in Order 636 and changes in gas usage, the average gas consumption per customer has not increased in the United States subsequent to 1992 but has gone down. The following table shows the average natural gas consumption for residential, commercial and industrial consumers from 1992 to 2008, as reported by the United States Energy Information Administration (EIA):

United States Average Consumption per Customer
(Mcf per Customer)

Source: United States Energy Information Administration
Natural Gas Consumption by End Use
Issued 4/29/2010

Year	Residential	Commercial	Industrial
1992	89.6	635.6	Not Available
1993	94.3	640.9	Not Available
1994	90.8	638.5	Not Available
1995	89.3	653.7	Not Available
1996	94.8	669.1	Not Available
1997	88.7	675.2	36,238.9
1998	78.9	594.6	36,784.9
1999	81.2	607.7	35,384.4
2000	84.3	635.1	36,968.0
2001	79.1	605.0	33,840.3
2002	80.0	620.8	36,457.7
2003	82.1	617.1	34,792.7
2004	77.9	608.8	34,645.1
2005	75.9	576.9	31,991.2
2006	68.1	537.0	33,597.0
2007	72.7	567.5	33,527.3
2008	74.7	590.9	33,838.3

As can be seen from this table, there has been a fairly steady downward trend in natural gas consumption by all three types of customers. LG&E has seen this same pattern. Therefore, Mr. Watkins' claim that FERC's adoption of a straight fixed variable rate design alone has resulted in increased consumption cannot be substantiated. In fact, it would be much more reasonable to make just the opposite inference based on this empirical data.

Q. Setting aside Mr. Watkins' claims, don't you believe that by recovering fixed costs though a basic service charge rather than a volumetric charge will provide less of an incentive for customers to conserve?

A. I don't believe that the adoption of a Straight Fixed Variable rate design will have a measurable impact on the usage behavior of most customers. As I mentioned in my direct testimony, it is likely that some customers that are using natural gas solely for discretionary uses such as fireplace logs, backyard grills, or decorative lighting will choose to discontinue taking gas service. It has been my experience that customers are less aware of the impact of changes in particular components of the rate than they are the overall levels of their bills. For a residential customer with an annual usage equal to the class average, there will be no impact from the adoption of a Straight Fixed Variable rate design. For the majority of LG&E's residential customer, the increase in the basic service charge will have a relatively small impact on their average total bills. A more important consideration is whether it makes good economic sense to recover fixed costs through a volumetric charge in order to provide customers an artificial inducement to encourage them to conserve.

Any incentive that is provided by pricing fixed costs on the basis of a volumetric charge – which would likely be small – comes at a very high price. Recovering fixed costs through a volumetric charge sends a distorted price signal to customers. It is important to keep in mind that when customers reduce their natural gas consumption, the Company avoids the cost of buying natural gas from its suppliers. Thus, when customers reduce their gas consumption the reduction in the commodity component of their bill (i.e. the amount billed through the application of the Gas Supply Component) is matched by a corresponding reduction in the amount of natural gas that the Company buys from its suppliers. Hence, conservation results in gas supply costs that can be avoided by the Company. But when customers reduce their gas consumption there is not a corresponding reduction in the Company's fixed costs. For example, the costs associated with distribution mains do not disappear simply because customers conserve natural gas. What happens is that the Company fails to recover its costs when customers use less natural gas. When fixed distribution costs are recovered through a volumetric charge, customers are given an artificial signal that reductions in their usage will result in a corresponding reduction in the Company's fixed costs, which is not the case. Recovering fixed costs through a volumetric charge sends a distorted priced signal to customers, making them believe that they are avoiding more costs than are actually being avoided.

Q. Ms. Brockway claims that the adoption of a Straight Fixed Variable rate design would violate the principle of "continuity" or "gradualism". Do you agree?

A. No. Rate continuity or gradualism has far more significance with respect to the impact on total customer bills than the impact on particular components of a bill. While the increase in the basic service charge is certainly significant when examined in isolation, it is more important to look at the expected impact on total bills. As explained earlier, most residential customers will not experience a significant change in their total bills as a result of the adoption of a Straight Fixed Variable rate design. However, if the Commission is concerned that the increase in the basic service charge is too large, then an alternative would be to move half way between the more bare-bones basic service charge shown from the Company's cost of service study (which does not include all fixed costs) and the basic service charge determined under the Straight Fixed Variable methodology in this proceeding. In particular, an alternative approach would be to increase the charge to $20.16, which is the midpoint between a charge of $13.80 which reflects customer-related costs from the cost of service study and a Straight Fixed Variable charge of $26.53, with the ultimate goal of moving to a full Straight Fixed Variable rate design in the next rate case. This alternative would represent a more gradual implementation of a Straight Fixed Variable rate design. If this alternative is adopted in lieu of the Company's proposal, a volumetric delivery charge would have to be included in the rate.

V. MISCELLANEOUS SERVICE CHARGES AND CUSTOMER DEPOSITS

A. LATE PAYMENT FEES

Q. Do you have any comments about modifying the late payment fees?

A. Yes. If the Commission decides to relax the Company's late payment charges, or even eliminate late payment charges altogether, the miscellaneous revenue collected during the test year through application of the late payment charges will need to be either reduced or eliminated and there will need to be a corresponding increase in the Company's base rate revenues. In developing its proposed rates, late payment charges act as a revenue credit in the determination of base rates. During the test year, pro-forma late payment charge revenues amounted to approximately $8.3 million (electric and gas). If the late payment charge were eliminated, for example, then these revenues would have to be added to the amount of revenue collected through base rates. In other words, the revenues collected through base rates would have to be $8.3 million higher if the late payment charge were eliminated. Of course, this has the effect of shifting revenues *from* customers that do not pay their bills on time *to* customers that do pay their bills on time.

B. CABLE TELEVISION ATTACHMENT CHARGE

Q. Please briefly describe the Company's proposed cable television pole attachment charge.

A. The CATV attachment charge that the Company is proposing in this proceeding is calculated using the same methodology that was approved by the Commission in its Order in Case No. 90-158 dated December 21, 1990, except that, in order to harmonize the LG&E and KU's tariffs, the Company is proposing to apply a single charge for attachments rather than to apply two separate charges based on pole size. The methodology approve by the Commission in Case No. 90-158 calculates the annual carrying costs of 35' to 45' poles and assigns a portion of the cost to the CATV attachment charge through the application of a usage space factor (12.24% for two-user poles and 7.59% for three-user poles). The carrying charges are calculated by applying a levelized fixed charge rate to original bare pole costs as recorded in the Company's accounting records. The bare pole costs used in the calculation excludes the cost of both major and minor appurtenances. The cost of major and minor appurtenances are recorded separately in the Company's continuing property records and are therefore not included in the pole costs used to calculate the CATV attachment charge.

Q. KCTA witness Kravtin claims that the Company did not properly exclude appurtenances in the calculation of the CATV attachment charge. Is she correct?

A. No. In developing her proposed CATV attachment charges, Ms. Kravtin reduced pole costs by a 15% factor to account for appurtenances. The 15% factor is arbitrary and not supported by any evidence submitted in this proceeding. As the Company stated in the response to Question No. 31 of KCTA's Supplemental Data Request, dated April 2, 2010, the cost of *all* appurtenances have been excluded from the bare pole costs used to calculate the CATV attachment charge.

Q. Are appurtenances recorded separately in the Company's continuing property records?

A. Yes. All appurtenances charged to Account 364 – Power, Towers and Fixtures are recorded separately in the Company's continuing property records. Attached as Seelye Rebuttal Exhibit 10 is the Company's response to Question No. 2 of KCTA First Data Request dated March 1, 2010. Appurtenances are recorded separately from bare pole costs and are identified under descriptions labeled "Brackets", "Cross Arms", "Fence", "Guy", and "Platforms". It is important to note that the Company did not use the entire amount of costs recorded in Account 364, as is often done to calculate a CATV attachment charge, even though a strong argument could be made that items such as guy wires and fencing should reasonably be included in the CATV attachment charge.

Q. Are so-called "minor appurtenances" included in the bare pole costs included in the CATV attachment charge?

A. No. Although the term "minor appurtenances" is vague and imprecise, costs such as aerial cable clamps, pole top pins and other such items that relate to connecting conductors to poles are not recorded in Account No. 364 - Poles, but, rather, in Account No. 365 – Overhead Conductor. Items related to connecting transformers to poles are recorded in Account 368 – Transformers. Although these items are not recorded in Account 364 – Poles, Towers and Fixtures, it is important to understand that these minor items would typically account for less than one percent of the cost of a typical project.

Q. Do you agree with Ms. Kravtin that an error was made by applying levelized carrying charge rate to gross investment?

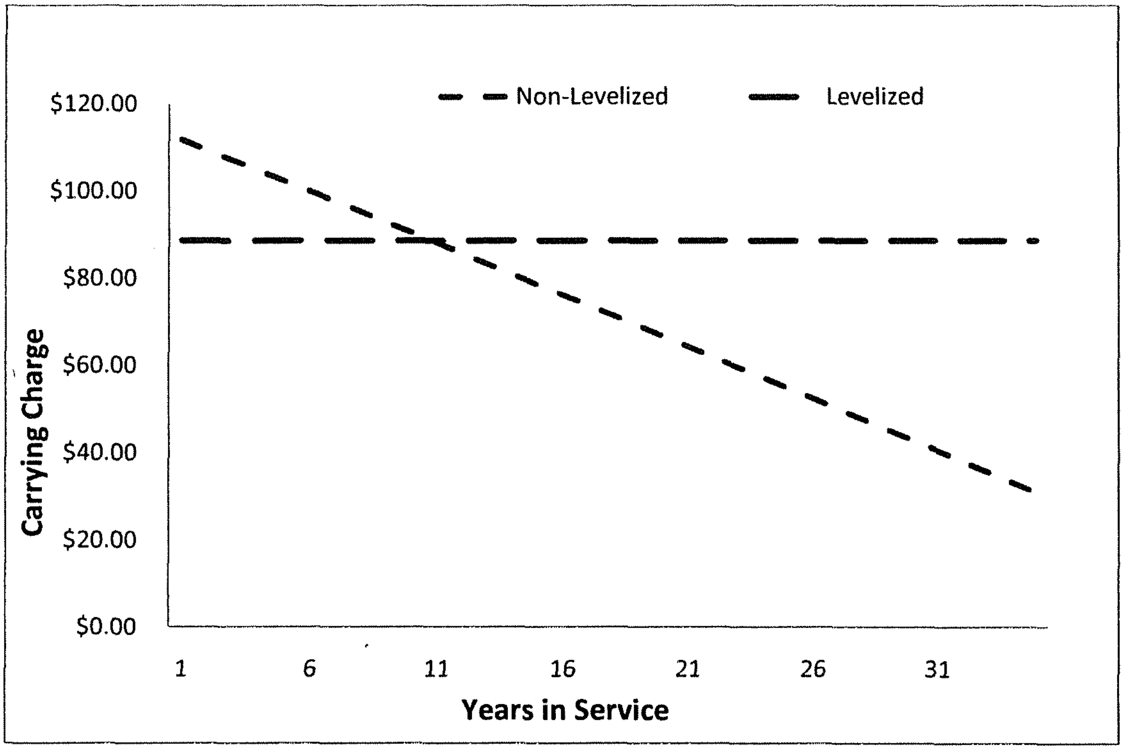
A. No. There are two accepted methodologies for calculating carrying charges – a levelized carrying charge approach and a non-levelized carrying charge approach. Both are standard approaches, both are accepted by the FERC, and, more importantly, both have been routinely accepted by the Commission in Kentucky. It is important to note that either methodology will produce the same result on a present value basis if consistently applied over the life of the investment. But once a particular methodology is selected it is not appropriate to swing back and forth between the two methodologies – selecting whichever method that yields a result that might be desired by one party or another. The reason for this is that during certain periods over the life of an investment a non-levelized carrying charge rate will be higher than a levelized carrying charge rate while during other periods a levelized carrying charge rate will be higher than a non-levelized rate.

Q. Which method was used by the Company the last time the CATV charge was calculated?

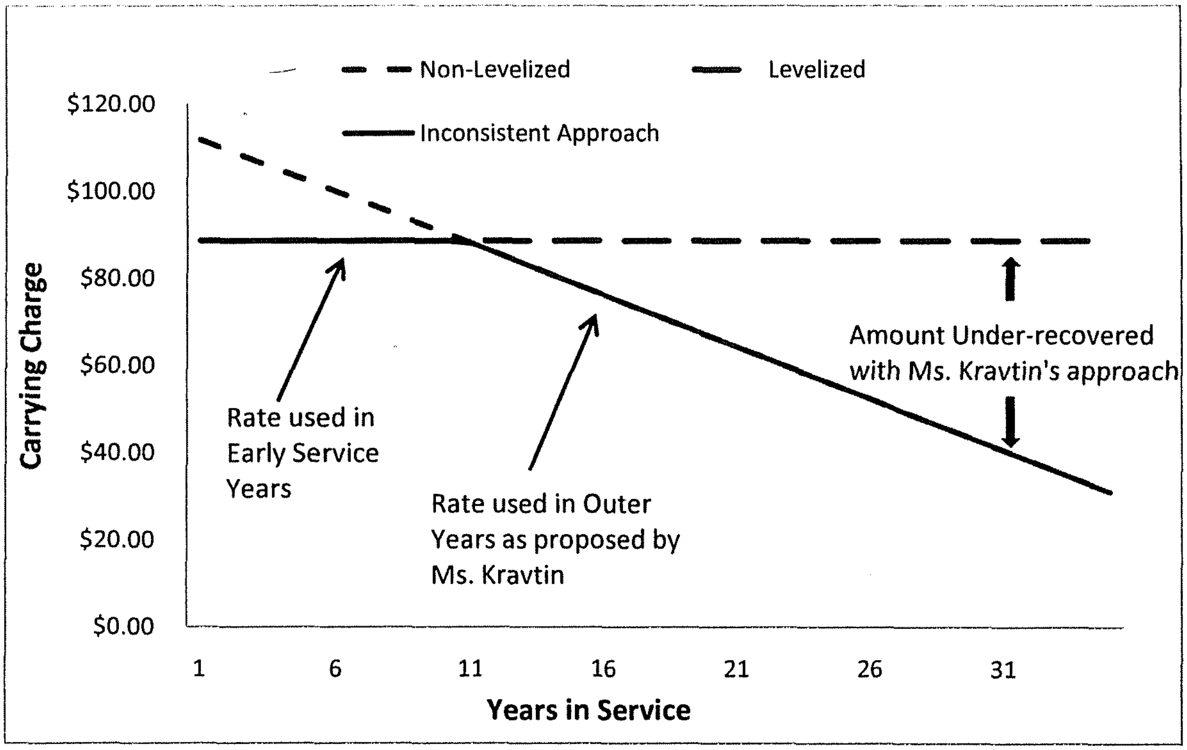
A. In Case No. 90-158 a levelized carrying charge methodology was used. A levelized carrying charge is calculated by applying a capital recovery factor to a gross investment. It is also called a "levelized gross plant" rate. A capital recovery factor is equal to the rate of return on investment plus a sinking fund depreciation factor. In Case No. 90-158, carrying charges were determined by applying a capital recovery factor (rate of return plus sinking fund depreciation factor) to the net plant investment in 35' to 45' poles, which is the standard procedure for calculating levelized carrying charges to determine a service rate.

Q. Is there anything fundamentally wrong with using a non-levelized carrying charge rate?

A. No, but it is not appropriate to switch back and forth between the two methodologies. As I mentioned, on a present value basis the two methodologies are equivalent over the life of the investment. The economic equivalency of the two methodologies was demonstrated in the Company's response to Question No. 3(a) of the Third Request of Commission Staff dated March 26, 2010, which is included as Seelye Rebuttal Exhibit 11. Particularly, Table I of that response shows that, over the life of an investment, the present value of levelized gross plant carrying charges equal the present value of non-levelized net plant carrying charges. However, at any given point in time the charges will be different. As the name implies, a levelized gross-plant carrying charge is designed to be level over the life of an investment, while a non-levelized net plant carrying charge will change from one year to the next. The following is a graphical comparison of the levelized and non-levelized charges shown in following graph:



As can be seen from this graph, in the early years of an investment, the levelized carrying charge is lower than the non-levelized carrying charges, but later on the levelized carrying charge is higher than the non-levelized charges. Because a levelized carrying charge rate results in a lower rate in the early years but a higher rate in outward years, switching from a levelized rate that has been in place for a long period of time to a non-levelized rate would result in a significant under-recovery of costs over the life of an investment. In other words, it would be inappropriate to use a levelized carrying charge rate during the early years of an investment but switch to a non-levelized charge after the two charges cross over, as illustrated in the following graph:



Q. From the results shown in Table I, can you quantify the impact of switching over from a levelized carrying charge rate to a non-levelized carrying charge rate?

A. Yes. Seelye Rebuttal Exhibit 12 shows the present value calculations from Table I included in the response to the Staff's data request, but a third set of columns has been added that illustrates what happens when a levelized gross plant carrying charge rate is used during the earlier years of an investment but switching over to a non-levelized net plant carrying charge rate at the cross-over point. As can be seen from

Seelye Rebuttal Exhibit 12, the present value of the consistently-applied non-levelized carrying charges is equal to the original $1,000 investment used in the example. Likewise, the present value of the consistently-applied non-levelized carrying charges is also equal to the original $1,000 investment. As mentioned earlier, this illustrates the mathematical and economic equivalency of the two methodologies when they are both consistently applied over the life of the investment. But when a levelized carrying charge rate is used in the earlier years but a non-levelized carrying charge rate is used in the outer years, as illustrated in the last two columns of the exhibit, the present value revenue requirement is only $907. Therefore, in this example, an inconsistent blending of the application of a levelized carrying charge rate during the early years with a non-levelized rate during the outer years would result in an under-recovery of costs over the life of the investment.

Q. Is Ms. Kravtin proposing to switch from a levelized rate to a non-levelized rate?

A. Yes. LG&E has been using a levelized rate since the early 1980s. Not only was a levelized carrying charge rate used determine the CATV attachment charge in Case No. 90-158, a levelized charge rate was used to calculate the CATV attachment charges when they were originally developed in the early 1980s.

Q. What is the FERC's policy on switching back and forth between a levelized gross plant carrying charge rate and a non-levelized net plant carrying charge rate?

A. FERC generally does not allow switching back and forth between the two methodologies. In a series of cases involving levelized carrying charges, the FERC rejected attempts to switch from a "net plant" approach to a "levelized" approach in midstream, finding that "allowing Consumers to switch pricing methodologies from the nonlevelized approach … to the levelized approach … is inappropriate." *Consumers Energy Co., Opinion No. 429*, 85 FERC ¶ 61,100 at 61,366 (1998), *reh'g granted, Opinion No. 429-A,* 89 FERC ¶ 61,138 (1999), *reh'g denied, Opinion No. 429-B*, 95 FERC ¶ 61,084 (2001); *accord Ky. Utils. Co., Opinion No. 432*, 85 FERC ¶ 61,274 at 62,105 (1998). In its *Opinion 432*, the FERC did not allow Kentucky Utilities Company ("KU") to change methodologies, stating as follows:

> In conclusion, we believe that either a levelized gross plant or a non-levelized rate design can produce comparable, reasonable results if they are used consistently. Here, however, KU proposes to switch methods. In supporting such a switch, a utility must prove that its proposed method is reasonable in light of its past recovery of capital costs using a different method. Here, KU has not persuaded us that the switch is appropriate in the circumstances of this case.

In the instant proceeding, Ms. Kravtin has not demonstrated that switching from a methodology that has been utilized for approximately 30 years would be reasonable in light of its past recovery of capital costs.

Q. Even though she proposes to calculate carrying charges using net plant, Ms. Kravtin proposes to continue to utilize sinking fund depreciation. Is this appropriate?

A. No. This is a serious error which significantly understates the cost of providing pole attachment service to CATV companies. It is not appropriate to use a sinking fund depreciation factor in connection with net plant. If a sinking factor is to be utilized, then it should be applied to gross plant, not net plant. As was shown in Seelye Rebuttal Exhibit 11 and Seelye Rebuttal Exhibit 12, carrying charges calculated by applying a levelized carrying charge rate (which included the return plus sinking fund depreciation) is mathematically equivalent on a present value basis to carrying charges calculated using straight line depreciation with net plant.

Ms. Kravtin claims to have corrected the carrying charge calculation to put it on an "apples-to-apples" basis, but she has in fact done the opposite. If net plant is used in calculating carrying charges, then it cannot incorporate the use of sinking fund depreciation. The net plant approach is equivalent to the standard methodology use in any given year, such as the current rate case, to calculate revenue requirements. For example, the revenue requirements calculated in Mr. Rives' exhibits do not use sinking fund depreciation to determine the depreciation element included in revenue requirements. When net plant is used to calculate revenue requirements in a rate case, straight line depreciation rates and not sinking fund depreciation rates are used to determine test-year depreciation expenses.

Q. Do you have any comments concerning Ms. Kravtin's adjustment to operation and maintenance expenses?

A. Yes. Her adjustment would exempt CATV companies of all responsibility for paying any of the cost of the storms that occurred during the test-year. During the test year, $1,366,766 of expenditures were charged to Maintenance of Poles, Towers and Fixtures (Subaccount 593001). However, an adjustment was made to this account to transfer $913,946 to a regulatory asset for storm-related costs, resulting in test-year expenses included in revenue requirements of $452,820 ($1,366,766 - $913,946 = $452,820). The problem with Ms. Kravtin's adjustment is that she removes the amount charged to the regulatory asset without adding back any amortization of the

$913,946 of storm-related expenditures charged to the regulatory asset. By simply removing the $913,946 of storm-related expenditures, Ms. Kravtin would excuse CATV companies from paying their fair share of storm-related costs. Instead of simply removing all of the test-year charges for Maintenance of Poles, Towers and Fixtures a more reasonable approach would have been to reduce test-year expenses for the $913,946 amount charged to the regulatory asset but add back a five-year amortization of the charges, resulting in an expense of $635,609 ($1,366,766 - $913,946 + [$913,946 ÷ 5 years] = $635,609.

Ms. Kravtin makes the same type of adjustment for Tree Trimming expenses. She removes $2,398,516 of storm-related charges that were originally recorded in Tree Trimming (Subaccount 593004) but were subsequently captured in the regulatory asset for storms. She then fails to add back an amortization of these storm-related charges. Again, a more reasonable approach would have been to reduce test-year expenses for the $2,398,516 amount charged to the regulatory asset but add back a five-year amortization of the charges, producing an expense of $2,856,770 ($4,775,583 - $2,398,516 + [$2,398,526 ÷ 5 years] = $2,856,770).

Q. Who ends up footing the bill if the Commission accepts Ms. Kravtin's unreasonable recommendations?

A. All other LG&E customers would pay the costs. Ms. Kravtin's recommendations will simply lower LG&E miscellaneous revenue. Lowering these miscellaneous revenues simply shifts the costs that would otherwise be recovered from CATV customers to LG&E's other customers, particularly residential customers who receive the largest percentage of the revenue credit from CATV attachment charges. From a revenue requirement perspective, lowering CATV attachment charges will therefore not affect the overall revenue that LG&E collects. Lowering CATV attachment charges will, however, affect LG&E's other customers. As with making changes to the late payment charges, making changes to lower the CATV charge will result in a larger amount of revenue that must be collected through base rates. Because of the Company's financial neutrality with respect to the level of the CATV attachment charges, LG&E's position regarding the proper calculation of the charges should be given greater weight by the Commission than the KCTA position, which seeks to obtain lower rates for CATV companies.

Q. Are there corrections that should be made to the LG&E's proposed CATV charge?

A. Yes. There are a number of changes that should be made to the proposed CATV attachment charge. First, it has come to my attention that an incorrect income tax rate was used in the carrying charge calculation. An income tax rate of 37.1912% should have been utilized. Second, plant costs as of November, 2009, were inadvertently used instead of October, 2009, which is the last month of the test year, to calculate pole costs. Third, the calculation should have included a five-year amortization of costs charged to the regulatory asset for storms rather than the unadjusted charges during the test year. A recalculation of the proposed CATV charge is included in Seelye Rebuttal Exhibit 13.

C. CUSTOMER DEPOSITS

Q. AARP witness Brockway recommends that the Company maintain its current customer deposit requirements. Are the deposit requirements proposed by LG&E consistent with the Commission's regulations?

A. Yes. The Commission's regulations 807 KAR 5:005, Section 7(b) state that, "The utility may establish an equal amount for each class based on the average bill of customers in that class. Deposit amounts shall not exceed two-twelfths (2/12) of the average bill of customers in the class where bills are rendered monthly...." The proposed deposit requirement of $160 for residential electric customers is less than two-twelfths of the average bill of customers in the class at the proposed rates, which is equal to $164. (See Seelye Exhibit 7, Page 1 – ({$339,321,953 ÷ [4,131,523 customer-months ÷ 12 months] x (2/12) = $164}.) The proposed deposit requirement of $115 for residential gas customers is also less than two-twelfths of the average bill of customers in the class at the proposed rates, which is equal to $116. (See Seelye Exhibit 10, Page 1 – ({$201,355,442 ÷ [(1,038,361 customer-months + 2,445,080 customer-months) ÷ 12 months] x (2/12) = $116}.) Therefore, both of these deposits are determined in accordance with the Commission's regulations.

VI. PRO-FORMA ADJUSTMENTS

A. ELECTRIC TEMPERATURE NORMALIZATION ADJUSTMENT

Q. Do you agree with Mr. Watkins's criticism that the temperature normalization adjustment should not be performed on a month-by-month basis?

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, the results obtained from performing the adjustment seasonally are not significantly different from the results obtained when the adjustment is performed monthly. However, 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 homogeneous 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.[10] 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-

[10] 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 standardized than linear regression modeling.

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 with Mr. Watkins that May should be considered a shoulder month?

A. No. Mr. Watkins makes an overly simplistic comparison between the average HDDs in May and the average CDDs in May. Although there are 72 HDDs and 123 CDDs during May, Mr. Watkins ignores the fact that the two figures are not comparable. On average, there are 4,189 HDDs on an annual basis, but only 1,564 CDDs on an annual basis. Therefore, the 123 CDDs during May represents a larger proportion of total CDDs than the relationship between the 72 HDDs during May to total HDDs. In addition, system loads during May also exhibit a pattern more representative of a summer month.

Q. Do you agree with Mr. Watkins that October is a shoulder month?

A. Yes. But, again, Mr. Watkins' comparison of the average number of HDDs during October to the number of CDDs during October is misleading. A factor that supports the month of October being treated as a summer month in the electric temperature adjustment is that approximately 80% of the fuel used for heating in the LG&E service territory is natural gas, electric energy response to cold weather is nominal, particularly during shoulder months such as October, and during the month of May, which I would not consider to be a shoulder month.

B. UNBILLED REVENUES

Q. KIUC witness Kollen recommends against removing unbilled revenues from test-year operating results. What are unbilled revenues?

A. Unbilled revenues represent the estimated revenues corresponding to timing differences that arise between when meters are read and the end of the month. Unbilled revenues arise because meters are read throughout the month on a meter-reading-cycle basis, whereas expenses are recorded on a calendar month basis. Because meters are read and bills are rendered on a billing-cycle basis, at the end of any month the utility will have sold gas or electric energy that the utility has not actually billed to customers, thus giving rise to the concept of "unbilled" revenues. Unbilled revenues represent an attempt to state revenues on a calendar month basis.

Q. How are unbilled revenues estimated?

A. Unbilled revenues are determined each month by developing an estimate of the Mcf or MWh sales that are unbilled. The unbilled Mcf or MWh sales are then allocated to the revenue classes on the basis of the as-billed sales for the month. An estimated price is then applied to the allocated Mcf or MWh unbilled sales to determine unbilled revenues for each revenue class. The estimated unbilled revenues for each revenue class are summed to obtain the unbilled revenues for the month.

Q. What is included in the estimated price applied to the unbilled Mcfs and MWHs?

A. The price used to compute unbilled revenues is an estimate of the *total* price to the consumer. The prices used to estimate unbilled revenues therefore include the gas supply component (GSC), fuel adjustment clause component (FAC), the environmental cost recovery surcharge (ECR), and demand-side management component (DSM), as applicable. The price used to estimate the unbilled revenues is thus an all-in price.

Q. Does LG&E compute unbilled revenues or unbilled Mcf/MWh sales by rate class?

A. No. Unbilled revenues and unbilled Mcf or MWh are not estimated for each rate class. The unbilled Mcf and MWh are estimated for total retail sales and then allocated to the *revenue classes* on the basis of actual sales during the month. Generally, there is little correspondence between the revenue classes reported in FERC Form 1, FERC Form 2 and other financial statements and the rate classes used to develop rates in a general rate case.

Q. Does LG&E compute unbilled demand units (Mcfs/day or kWs) for rate classes that have demand charges?

A. No. Several of LG&E's electric rate schedules and all of its electric special contracts include demand charges, and two of LG&E's gas special contracts are billed under rates that include demand charges. The technique used to estimate unbilled revenues provides only a high-level estimate of the unbilled Mcf or MWh. It is not refined enough to develop unbilled demands.

Q. What entries are made to record unbilled revenues during a month?

A. Two entries are made: First, unbilled revenues for the current month are added to actual billed revenues for the current month. Second, the unbilled revenue amount recorded in the previous month is subtracted from the actual billed revenues for the current month. Since the as-billed revenues for the current month includes the unbilled revenues that were recorded in the prior month, this amount needs to be subtracted from actual revenues billed for the current month.

The following table shows the unbilled entries for LG&E's gas operations during the test year:

UNBILLED GAS REVENUES FOR THE 12 MONTHS ENDED OCTOBER 2009			
MONTH	**UNBILLED REVENUE FOR CURRENT MONTH**	**UNBILLED REVENUE FOR PREVIOUS MONTH**	**NET UNBILLED REVENUES**
November 2008	$30,572,000	**$18,811,000**	$11,761,000
December	$39,704,000	$30,572,000	$9,132,000
January 2009	$45,222,000	$39,704,000	$5,518,000
February	$29,946,000	$45,222,000	($15,276,000)
March	$19,041,000	$29,946,000	($10,905,000)
April	$11,639,680	$19,041,000	($7,401,320)
May	$5,346,000	$11,639,680	($6,293,680)
June	$3,059,492	$5,346,000	($2,286,508)
July	$3,350,000	$3,059,492	$290,508
August	$2,738,000	$3,350,000	($612,000)
September	$3,406,000	$2,738,000	$668,000
October	**$7,434,000**	$3,406,000	$4,028,000
Total Test-Year			**($11,377,000)**

For the twelve-month period, the entries in gray on the left column labeled "Unbilled Revenues for Current Month" cancel out the entries in gray on the right column labeled "Unbilled Revenues for Previous Month". Therefore, mathematically, the unbilled revenues for the test year, -$11,377,000, equals the unbilled revenues for October 2009, the last month of the test year, or $7,434,000, minus the unbilled revenues recorded for October 2010, the month prior to the beginning of the test year, or $18,811,000 (i.e., $7,434,000 – $18,811,000 = -$11,377,000). Consequently, for the twelve-month period only two entries actually come into play in determining the unbilled revenues – the unbilled revenues for October 2009 that are *added* during the last month and the unbilled revenues for October 2008 that are *subtracted* during the first month.

The following table shows the unbilled entries for LG&E's electric operations during the test year:

UNBILLED ELECTRIC REVENUES FOR THE 12 MONTHS ENDED OCTOBER 2009

MONTH	UNBILLED REVENUE FOR CURRENT MONTH	UNBILLED REVENUE FOR PREVIOUS MONTH	NET UNBILLED REVENUES
November 2008	$31,790,000	**$32,535,000**	($745,000)
December	$32,519,000	$31,790,000	$729,000
January 2009	$32,727,000	$32,519,000	$208,000
February	$32,784,000	$32,727,000	$57,000
March	$39,814,000	$32,784,000	$7,030,000
April	$39,013,454	$39,814,000	($800,546)
May	$37,929,551	$39,013,454	($1,083,903)
June	$47,704,348	$37,929,551	$9,774,797
July	$44,218,000	$47,704,348	($3,486,348)
August	$48,488,000	$44,218,000	$4,270,000
September	$44,625,000	$48,488,000	($3,863,000)
October	**$35,406,000**	$44,625,000	($9,219,000)
Total Test-Year			**$2,871,000**

Electric unbilled revenues for the test year, $2,871,000, equals the unbilled revenues for October 2009, the last month of the test year, or $35,406,000, minus the unbilled revenues recorded for October 2008, the month prior to the beginning of the test year, or $32,535,000 (i.e., $35,406,000 – $32,535,000 = $2,871,000).

Q. Did LG&E make pro-forma adjustments to eliminate unbilled revenues from test-year operating revenues?

A. Yes. Consistent with LG&E's last four rate cases (Case No. 2008-00252, Case No. 2003-00433, Case No. 2000-080 and Case No. 90-158), unbilled revenues were removed from test-year operating results.

Q. Has the subject of removing unbilled revenues been considered in any of these cases?

A. Yes. In Case No. 90-158, LG&E offered testimony by Benjamin A. McKnight, an outside accounting expert, in support of an adjustment to remove unbilled revenue from test-year operating results. After a thorough consideration of the issue, the Commission accepted LG&E's proposed adjustment. (Order in Case No. 90-158, dated December 21, 1990, p. 18.) LG&E proposed an adjustment in Case No. 2000-080 to eliminate unbilled revenues, which was approved in the Commission's Order dated September 27, 2000. LG&E and KU proposed adjustments in Case Nos. 2003-00433 and 2003-00434 to eliminate unbilled revenues. The adjustments to eliminate unbilled revenue were considered extensively in those proceedings. In its Order in Case No. 2003-00433, the Commission stated that "LG&E's arguments convince us that any resulting mismatch [between unbilled revenues and expenses] is adequately mitigated by the various normalization adjustments included in its rate application." (Order in Case No. 2003-00433, p. 26.) KU and LG&E also proposed adjustments in

Case Nos. 2008-00251 and 2008-00252 to eliminate unbilled revenues. Those rate cases settled.

Q. In this proceeding, have any of the intervenor witnesses offered recommendations regarding the Company's pro-form adjustment?

A. Yes. KIUC witness Kollen simply proposes to leave unbilled revenues in test-year operating results. Mr. Kollen's adjustment would have the effect of increasing electric revenues by $2,871,000. Although he does not make a recommendation regarding LG&E's gas operations, leaving unbilled revenues in test-year operating results would have the effect of decreasing gas revenues by $11,377,000. Thus, if consistently applied for both gas and electric operations, Mr. Kollen's approach would *increase* LG&E's total revenue request for gas and electric operations by $8,506,000.

Q. Are there any problems with leaving unbilled revenues in test year operating results as proposed by Mr. Kollen?

A. Yes. Besides being contrary to past Commission practice, there are numerous problems with leaving unbilled revenues in test-year operating results. One problem is the unbilled revenues that Mr. Kollen proposes to add to test-year income reflect revenue amounts related to fuel costs, environmental costs, demand-side management costs, gas supply costs, and other items, all of which have already been removed from test year expenses. Recall that unbilled revenues were computed by applying the all-in price of gas and electric energy to the estimated unbilled sales (Mcf or kWh). These estimated prices include amounts for the FAC, ECR, DSM, and GSC. For example, the average price used to compute unbilled gas revenues for the residential class was $6.37/mcf for October 2009, which included a GSC component of

$4.6914/mcf. However, the gas supply expenses associated with the GSC component of the rate have been removed from test-year operating expenses.

Unbilled revenues include amounts for the FAC, ECR, DSM, and GSC even though the costs for these components have been eliminated from operating expenses. FAC costs were eliminated from operating expenses through the pro-forma adjustment shown on line 6 of Rives Exhibit 1 (Reference Schedule 1.03). ECR costs were eliminated from operating expenses through the pro-forma adjustment shown on line 8 of Rives Exhibit 1 (Reference Schedule 1.05). DSM costs were eliminated from operating expenses through the pro-forma adjustment shown on line 13 of Rives Exhibit 1 (Reference Schedule 1.10). All gas supply expenses, which account for as much as two thirds of unbilled gas revenues, were eliminated from operating expenses through the pro-forma adjustment shown on line 42 of Rives Exhibit 1 (Reference Schedule 1.39). Leaving unbilled revenues in test-year operating results seriously distorts revenue requirements by double counting these cost components.

Q. Are there any other problems with the unbilled revenue adjustments proposed by Mr. Kollen?

A. Yes. In addition to the unbilled revenues being significantly overstated by the inclusion of FAC, ECR, DSM, and GSC revenues, Mr. Kollen fails to account for the fact that various pro-forma adjustments in the rate case eliminate the need to consider unbilled revenues. Through the proper application of pro-forma adjustments, any need to even consider unbilled revenues disappears. If revenues and expenses are properly constructed in a rate case, there simply will not be any unbilled revenues.

Three major factors account for unbilled revenues during the test year: (1) rate differences due to changes in the FAC, ECR, DSM, GSC etc., (2) changes in the number of customers served, plant closings, and customer rate switching, and (3) changes in temperature. The purpose of making pro-forma adjustments is to develop test-year operating results that account for these and other factors. If the utility's rates did not change (as a result, for example, of changes in gas costs, environmental costs, fuel costs, etc.), if temperatures were normal every year, and if there were no changes in the number and composition of customers, a utility's unbilled revenues would be insignificant. Likewise, if the utility's revenues and expenses are properly adjusted for all relevant factors, consistent with methodologies found reasonable by the Commission, unbilled revenues will have been fully accounted for in the construction of pro-forma operating revenues and expenses.

Q. How do changes in price create unbilled revenues during the test year?

A. As mentioned earlier, unbilled revenues for the test year are calculated by adding the unbilled revenues for October 2009 and subtracting the unbilled revenues for October 2008. If the price in October 2009 is different than it was in October 2008, unbilled revenues would have been created for the test year even if there was no difference in the sales volume for the two months.

This is what happened in computing gas unbilled revenues for the test year. Practically all of LG&E's unbilled gas revenues recorded during the test year can be accounted for by the difference between the average prices from October 2008 to October 2009. Even though there was no change in the Company's base rates from October 2008 to October 2009, the average price used to compute unbilled revenues decreased from $17.85/Mcf to $6.37/Mcf for the residential class, due to lower gas costs. This decrease in price accounts for almost all of LG&E's unbilled gas revenues. By eliminating the GSC, FAC, ECR, DSM, and other components from revenues and expenses, as was done in LG&E's rate case application, any unbilled revenues created as a result of changes in the Company's rates have been fully accounted for.

Q. How do changes in the number of customers, plant closings, and customer rate switching create unbilled revenues?

A. If there are more customers served at the end of the test year than there were at the beginning of the test year, then, with everything else being equal, sales volumes and unbilled revenues will be higher for the month that is added (October 2009) than for the month that is subtracted (October 2008) in the computation of unbilled revenues for the year. Similarly, if there is a different customer composition at the beginning of the year than at the end of the year, as a result of plant closings or customer rate switching, then unbilled revenues will be created. Pro-forma adjustments were made to annualize revenues and expenses for year-end numbers of customers (line 15 of Rives Exhibit 1) and to reflect customer rate switching and customer plant closing (line 16 of Rives Exhibit 1). Therefore, by making pro-forma adjustments any unbilled revenues created as a result of these factors have been fully accounted for.

Q. How do changes in temperature create unbilled revenues?

A. If there were more degree days during the month for which unbilled revenues are added (October 2009) than there were during the month for which unbilled revenues were subtracted (October 2008) then, with everything else being equal, unbilled revenues would have been created for the test year. A pro-forma adjustment was made for LG&E's gas and electric operations to adjust revenues for normal temperature (lines 14 and 43 of Rives Exhibit 1). Therefore, any unbilled revenues created as a result of changes in temperature have been eliminated through the temperature normalization adjustment.

Mr. Kollen has not attempted to disentangle (1) the components of electric and gas unbilled revenues that have been fully accounted for though pro-forma adjustments made in this case *from* (2) the unbilled revenues attributable to changes in temperature, which has already been accounted for in this proceeding.

Q. Are there any other problems with the Mr. Kollen's recommendation of including unbilled revenue adjustments in test year operating results?

A. Yes. Mr. Kollen proposes to eliminate the unbilled revenue adjustment without adjusting the billing determinants used to develop rates in the proceeding. Selectively eliminating the pro-forma adjustment for unbilled revenues, without modifying other key exhibits in the rate case would result in improperly calculated rates.

The billing determinants used to develop the proposed electric rates in Seelye Exhibit 7 and the proposed gas rates in Seelye Exhibit 10 were reconciled back to as-billed revenues, which *excluded* unbilled revenues. If unbilled revenues were left in test-year operating results, it would be necessary to develop a fair and equitable methodology for estimating billing determinants that would need to be added to or subtracted from those shown in Seelye Exhibit 7 and Seelye Exhibit 10. In compiling the billing determinants used to develop the proposed rates, the rates in effect during the test year were applied to the as-billed billing determinants to test the accuracy of the billing determinants to be used to develop the Company's proposed rates. The results of this reconciliation to as-billed revenues are shown for electric as-billed revenue in Seelye Exhibit 5 and for gas as-billed revenues in Seelye Exhibit 8. If an adjustment were not made to eliminate unbilled revenues, then a complex and ultimately subjective methodology would need to be developed to reconstruct the billing determinants so that they include the "billing determinants" associated with the unbilled amounts. This would introduce a great deal of subjectivity into the process of developing the proposed rates, and would create another arena for disagreements about whether the approach used to allocate the unbilled revenues and associated billing units among the rate classes was equitable (similar to the disagreements in this proceeding over the methodology used in the cost of service study).

Q. What other exhibits would have to be modified in order to set rates that properly account for unbilled revenues if they were not eliminated from test-year operating results?

A. In addition to modifying the reconstruction of billing determinants in Seelye Exhibits 5 and 8 and the development of the proposed rates rate in Seelye Exhibits 7 and 10, the gas and electric year-end adjustments shown in Seelye Exhibits 20 and 21 and the electric and gas temperature normalization adjustments shown in Seelye Exhibits 18 and 19 would have to be modified to reflect unbilled revenues. All of these exhibits were prepared on an as-billed basis and would need to be reconstructed on an unbilled basis to properly set rates in this proceeding.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principal and Senior Analyst with The Prime Group, LLC, 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.

W. Seelye

William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

Seelye Rebuttal Exhibit 1

**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	$2,255,143,669	$1,806,370,079	$95,843,606
Depreciation Reserve - Production	$1,132,956,587	$907,498,226	$48,150,655
Production Net Plant	$1,122,187,082	$898,871,853	$47,692,951
Production Expenses Allocated by Watkins on Production Plant			
502 Steam Exspenses	$35,831,155	$28,700,755	$1,522,824
505 Electric Expenses	$741,669	$594,077	$31,521
506 Misc Steam Power Expense	$19,305,537	$15,463,735	$820,485
507 Rents	$0	$0	$0
509 Allowances	$4,878	$3,907	$207
511 Maintenance of Structures	$2,262,456	$1,812,227	$96,154
536 Water For Power	$39,044	$31,274	$1,659
537 Hydraulic Expenses	$0	$0	$0
538 Electric Expenses	$164,110	$131,452	$6,975
539 Misc Hydraulic Power Expenses	$118,633	$95,025	$5,042
540 Rents	$376,801	$301,818	$16,014
542 Maintenance of Structures	$203,936	$163,353	$8,667
543 Maintenance of Reserves, Dams, & Waterways	$86,508	$69,293	$3,677
546 Operation Supervision & Engineering	$31,105	$24,915	$1,322
548 Generation Expense	$127,492	$102,121	$5,418
549 Misc Other Power Generation	$41,162	$32,971	$1,749
550 Rents	$0	$0	$0
551 Maintenance Supervision & Engineering	$40,120	$32,136	$1,705
552 Maintenance of Structures	$65,277	$52,287	$2,774
553 Maintenance of Gen & Electric Plant	$1,480,185	$1,185,628	$62,908
554 Maintenance of Misc Other Power Generation	$161,443	$129,316	$6,861
555 Purchased Power - Demand	$10,299,122	$8,249,597	$437,713
556 System Control & Load Dispatch	$1,445,355	$1,157,729	$61,428
557 Other Expenses	$2,008,235	$1,608,596	$85,350
Sub-Total	$74,834,223	$59,942,213	$3,180,454
Production Depreciation Expense	$85,053,049	$68,127,492	$3,614,755

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	$23,926,487	$19,165,116	$1,016,876
Equity return	$69,494,241	$55,664,887	$2,953,505
Income Tax	$41,964,044	$33,613,199	$1,783,472
Revenue For Return	135,384,772	$108,443,202	$5,753,853
Production Expenses	$74,834,223	$59,942,213	$3,180,454
Depreciation Expense	$85,053,049	$68,127,492	$3,614,755
Total Plant Related Revenue Requirement	$295,272,044	$236,512,907	$12,549,062
kWh in Costing Period		12,197,715,000	2,585,396,000
Cost per Kwh		$0.019	$0.005

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	$2,889,368	$1,767,698	$810,497	$311,173	$2,889,368
Intermediate	$151,136		$109,208	$41,928	$151,136
Peak	$557,018			$557,018	$557,018
Total	$3,597,521	$1,767,698	$919,704	$910,119	$3,597,521
Percentage of Total		49.14%	25.56%	25.30%	

	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 2

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 $\mathbf{V} \neq \mathbf{I}$.

ICS

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

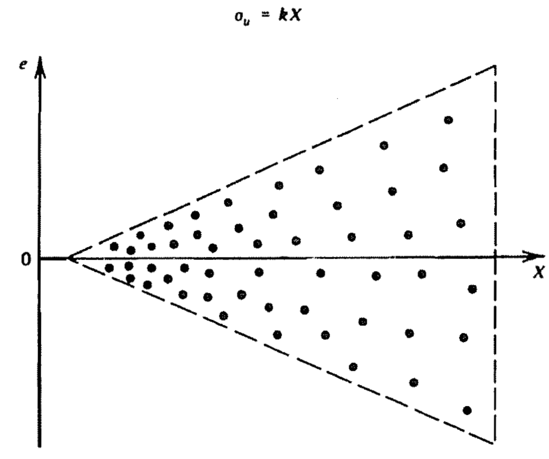

Fig. 5.1. Heteroscedastic residuals.

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

$$Y_i = \beta_0 + \beta_1 X_{1i} + \beta_2 X_{2i} + \cdots + \beta_6 X_{6i} + u_i. \tag{5.3}$$

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 $\overline{Y}$ 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

$$\kappa(DA) \leq \kappa(D)\kappa(A) = \gamma\kappa(A).$$

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 $A_1x = b_1$; 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 $B = A^TA$ 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^TL 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 $L_{11}^TL_{11}$ and $L_{22}^TL_{22}$, respectively, then the Cholesky factor of L^TL will have the form

$$R = (1 + O(\gamma^{-2}))\begin{pmatrix} R_{11} & \frac{1}{\gamma}(L_{21}R_{11}^{-1})^TL_{22} \\ & R_{22} \end{pmatrix};$$

cf. Stewart [742, 1984]. After solving $RR^Ty = L^Tb$ 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

$$\text{(4.4.7)} \qquad \min_x \left\| \begin{pmatrix} A_2 \\ \gamma A_1 \end{pmatrix} x - \begin{pmatrix} b_2 \\ \gamma b_1 \end{pmatrix} \right\|_2^2$$

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

$$\text{(4.4.8)} \qquad \tilde{P} W \tilde{P}^T = W = \operatorname{diag}(w_1, \dots, w_m).$$

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 $W = \mathrm{diag}\,(0, W_2)$, 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.

ECONOMETRIC METHODS

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University of California, Irvine

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IN MEMORY OF
B. and J.

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Maximizing $\ln L$ with respect to $\boldsymbol{\beta}$ implies minimizing the weighted sum of squares

$$(\mathbf{y} - \mathbf{X}\boldsymbol{\beta})'\boldsymbol{\Omega}^{-1}(\mathbf{y} - \mathbf{X}\boldsymbol{\beta}) = \mathbf{y}'\boldsymbol{\Omega}^{-1}\mathbf{y} - 2\boldsymbol{\beta}'\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{y} + \boldsymbol{\beta}'\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{X}\boldsymbol{\beta}$$

Differentiating with respect to $\boldsymbol{\beta}$ and equating to zero gives

$$\mathbf{b}_* = (\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{X})^{-1}\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{y}$$

as in Eq. (8-18).

An unbiased estimator of σ^2 may be derived from the application of OLS to Eq. (8-14). It is

$$\begin{aligned} s^2 &= \frac{(\mathbf{Ty} - \mathbf{TXb}_*)'(\mathbf{Ty} - \mathbf{Txb}_*)}{n - k} \\ &= \frac{(\mathbf{y} - \mathbf{Xb}_*)'\mathbf{T}'\mathbf{T}(\mathbf{y} - \mathbf{Xb}_*)}{n - k} \\ &= \frac{(\mathbf{y} - \mathbf{Xb}_*)'\boldsymbol{\Omega}^{-1}(\mathbf{y} - \mathbf{Xb}_*)}{n - k} \\ &= \frac{\mathbf{y}'\boldsymbol{\Omega}^{-1}\mathbf{y} - \mathbf{b}_*'\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{y}}{n - k} \end{aligned} \tag{8-22}$$

On the assumption of normality for the disturbance term all the inference procedures of Chaps. 5 and 6 carry through for this model. Thus the test of

$$H_0\colon \quad \mathbf{R}\boldsymbol{\beta} = \mathbf{r}$$

is based on

$$F = \frac{(\mathbf{r} - \mathbf{Rb}_*)'\left[\mathbf{R}(\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{X})^{-1}\mathbf{R}'\right]^{-1}(\mathbf{r} - \mathbf{Rb}_*)/q}{s^2}$$

having the $F(q, n - k)$ distribution under the null hypothesis, where $\mathbf{b}_*$ is the GLS estimator defined in Eq. (8-18) and s^2 the variance estimator defined in Eq. (8-22).

The above formulas are only operational if the elements of $\boldsymbol{\Omega}$ are known. In some exceptional cases this may be so, but in most practical cases it is not. We must therefore proceed to the development of operational procedures for such cases, but there is, in fact, no single procedure which is generally applicable. One must look for the procedure which is best suited to the features of each specific problem in turn, and that is done in the remaining sections of this chapter.

8-4 HETEROSCEDASTICITY

We have already mentioned in Sec. 8-1 the possibility of heteroscedastic disturbances in *cross-section* studies. Heteroscedasticity may also arise in dealing with grouped data. Suppose the model is

$$Y_t = \alpha + \beta X_t + u_t \qquad t = 1, \ldots, n$$

where the u_t are homoscedastic with zero covariances. However, suppose we only have access to data which have been averaged within m groups, where n_i indicates the number of observations in the ith group. The form of the model appropriate to the data is now

$$\bar{Y}_i = \alpha + \beta \bar{X}_i + \bar{u}_i$$

and clearly

$$\operatorname{var}(\bar{u}_i) = \frac{\sigma^2}{n_i} \qquad i = 1, \ldots, m$$

Thus

$$\sigma^2 \boldsymbol{\Omega} = \sigma^2 \begin{bmatrix} \frac{1}{n_1} & 0 & \cdots & 0 \\ 0 & \frac{1}{n_2} & \cdots & 0 \\ \cdots & \cdots & \cdots & \cdots \\ 0 & 0 & \cdots & \frac{1}{n_m} \end{bmatrix} \tag{8-23}$$

where $\boldsymbol{\Omega}$ is known and the GLS estimator can easily be computed.

Example 8-1 We have taken the same X, Y data as in Example 2-1, only now it is assumed that they relate to group means. The n_i column indicates the number of observations in each group. The overall means are easily computed from

$$\bar{X} = \frac{\Sigma n_i \bar{X}_i}{\Sigma n_i} = \frac{202}{50} = 4.04$$

$$\bar{Y} = \frac{\Sigma n_i \bar{Y}_i}{\Sigma n_i} = \frac{400}{50} = 8.00$$

which are almost identical with the simple means of 4 and 8 in Table 2-1. We assume that Eq. (8-23) is the appropriate assumption about $\operatorname{var}(\bar{\mathbf{u}})$, that is,

$$\operatorname{var}(\bar{\mathbf{u}}) = \sigma^2 \boldsymbol{\Omega} = \sigma^2 \begin{bmatrix} \frac{1}{n_1} & & & \\ & \frac{1}{n_2} & & \\ & & \ddots & \\ & & & \frac{1}{n_5} \end{bmatrix}$$

Thus

$$\boldsymbol{\Omega}^{-1} = \begin{bmatrix} n_1 & & & \\ & n_2 & & \\ & & \ddots & \\ & & & n_5 \end{bmatrix} = \begin{bmatrix} 12 & & & & \\ & 6 & & & \\ & & 11 & & \\ & & & 10 & \\ & & & & 11 \end{bmatrix}$$

It may then be seen that

$$\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{X} = \begin{bmatrix} 1 & 1 & \cdots & 1 \\ \bar{X}_1 & \bar{X}_2 & \cdots & \bar{X}_5 \end{bmatrix} \begin{bmatrix} n_1 & & & \\ & n_2 & & \\ & & \ddots & \\ & & & n_5 \end{bmatrix} \begin{bmatrix} 1 & \bar{X}_1 \\ 1 & \bar{X}_2 \\ \vdots & \vdots \\ 1 & \bar{X}_5 \end{bmatrix}$$

$$= \begin{bmatrix} \Sigma n_i & \Sigma n_i \bar{X}_i \\ \Sigma n_i \bar{X}_i & \Sigma n_i \bar{X}_i^2 \end{bmatrix}$$

and

$$\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{y} = \begin{bmatrix} \Sigma n_i \bar{Y}_i \\ \Sigma n_i \bar{X}_i \bar{Y}_i \end{bmatrix}$$

Formula (8-18) for the GLS estimator now simplifies to

$$\begin{bmatrix} \Sigma n_i & \Sigma n_i \bar{X}_i \\ \Sigma n_i \bar{X}_i & \Sigma n_i \bar{X}_i^2 \end{bmatrix} \mathbf{b}_* = \begin{bmatrix} \Sigma n_i \bar{Y}_i \\ \Sigma n_i \bar{X}_i \bar{Y}_i \end{bmatrix}$$

which is a form of weighted least squares. Applying the data from Table 8-1 gives

$$50b_{1*} + 202b_{2*} = 400$$

$$202b_{1*} + 1254b_{2*} = 2388$$

with solution $b_{1*} = 0.88$ and $b_{2*} = 1.76$. To obtain the sampling variance of these estimates, substitute for $\boldsymbol{\Omega}^{-1}$ from Eq. (8-23) in Eq. (8-22) to obtain for

Table 8-1

$\bar{X}_i$	$\bar{Y}_i$	n_i	$n_i\bar{X}_i$	$n_i\bar{Y}_i$	$n_i\bar{X}_i^2$	$n_i\bar{X}_i\bar{Y}_i$	$n_i\bar{Y}_i^2$
2	4	12	24	48	48	96	192
3	7	6	18	42	54	126	294
1	3	11	11	33	11	33	99
5	9	10	50	90	250	450	810
9	17	11	99	187	891	1683	3179
Sums		50	202	400	1254	2388	4574

this example

$$(n-k)s^2 = \Sigma n_i \bar{Y}_i^2 - [b_{1*} \quad b_{2*}] \begin{bmatrix} \Sigma n_i \bar{Y}_i \\ \Sigma n_i \bar{X}_i \bar{Y}_i \end{bmatrix}$$

$$= 4574 - [0.8791 \quad 1.7626] \begin{bmatrix} 400 \\ 2388 \end{bmatrix}$$

$$= 13.2712$$

Thus

$$s^2 = \frac{13.2712}{3} = 4.4237$$

Notice that the n which occurs in the denominator of the variance formula, Eq. (8-22), is the number of sample points. It is *not* the total number of observations underlying the sample points. In this example, the latter number is $\Sigma n_i = 50$, but $n = 5$. Finally, substitution in Eq. (8-19) gives

$$\operatorname{var}(\mathbf{b}_*) = s^2(\mathbf{X}'\mathbf{\Omega}^{-1}\mathbf{X})^{-1}$$

$$= 4.4237 \begin{bmatrix} 50 & 202 \\ 202 & 1254 \end{bmatrix}^{-1}$$

$$= 4.4237 \begin{bmatrix} 0.057271 & -0.009225 \\ -0.009225 & 0.002284 \end{bmatrix}$$

$$= \begin{bmatrix} 0.2533 & -0.0408 \\ -0.0408 & 0.0101 \end{bmatrix}$$

Thus

$$\operatorname{var}(b_{1*}) = 0.2533$$

$$\operatorname{var}(b_{2*}) = 0.0101$$

This example might have been treated equivalently by finding the $\mathbf{T}$ matrix satisfying $\mathbf{T}'\mathbf{T} = \mathbf{\Omega}^{-1}$. Given $\mathbf{\Omega}^{-1}$, the $\mathbf{T}$ matrix is simply

$$\mathbf{T} = \begin{bmatrix} \sqrt{n_1} & & & \\ & \sqrt{n_2} & & \\ & & \ddots & \\ & & & \sqrt{n_5} \end{bmatrix}$$

Thus the data of Table 8-1 could have been recorded as

X_i	$2\sqrt{12}$	$3\sqrt{6}$	$1\sqrt{11}$	$5\sqrt{10}$	$9\sqrt{11}$
Y_i	$4\sqrt{12}$	$7\sqrt{6}$	$3\sqrt{11}$	$9\sqrt{10}$	$17\sqrt{11}$

and OLS applied to these five pairs of numbers.

A different variant of a cross-section study is one with *replication* of the Y variable for given values of X. Suppose, for instance, that agronomists are investigating the variation of crop yield in response to varying applications of fertilizer. Let $X_1, \ldots, X_i, \ldots, X_m$ denote the different fertilizer dosages chosen for

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When the left-out variable is qualitative in nature, it is usually orthogonal to the independent variables and is often detected by the clustering of the residuals.

5.4 *Heteroscedastic Residuals*

Textbooks in econometrics often recommend plotting the residuals against the independent variables to check for heteroscedasticity. In some cases this may lead to wrong conclusions.

Heteroscedasticity relates to the *variance* of the error terms and not to patterns in the *values* of the error terms. The researcher expects to find the nature of the error of the variance of the error terms from the variance of the residuals. Since the number of residuals (observations) in a typical econometric research project is not large enough to accommodate any powerful techniques of test procedures based on inferences about the true variance, the researcher has to resort to other measures of dispersion.

A common measure in such situations is the range—the difference between minimum and maximum in a given subgroup. When the residuals are arranged according to a sequence believed to have caused heteroscedasticity, the researcher expects the range of the residuals to change when heteroscedasticity actually is present. There are several ways of approaching this problem; a commonly used procedure is to draw the envelope of all the residuals, as shown in Figure 5.3.

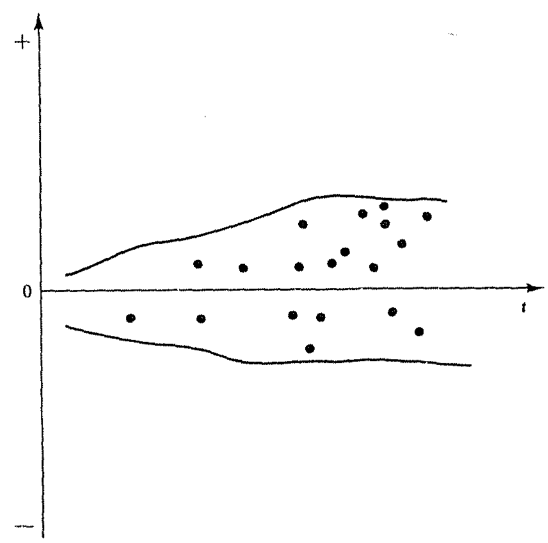


Figure 5.3. Envelope of Residuals

If the envelope expands or contracts systematically with respect to the arrangement of the residuals, then heteroscedasticity may be suspected. But this conclusion is valid only when the observations are reasonably large. In small samples, even though there is no heteroscedasticity in the true error terms, it may often be observed in the residuals arranged with respect to any of the independent variables in the regression that generated them. As we will now show, this is a consequence of the least squares estimation procedure; the researcher should guard against the possible misinterpretation of this phenomenon.

Consider the true relation

$$y_t = \beta x_t + \varepsilon_t, \tag{5.1}$$

where all the error terms (ε's) are randomly generated by the same statistical distribution with mean zero and variance σ_ε^2, and the variables are deviation from the means.

The residuals in the ordinary least squares estimation of (5.1) are

$$e_t = y_t - \hat{\beta} x_t. \tag{5.2}$$

Using (5.1) and the expression for the least squares estimation of $\hat{\beta}$ we obtain

$$e_t = \beta x_t + \varepsilon_t - \left(\sum x_t y_t / \sum x_t^2\right) x_t \tag{5.3}$$

$$= \varepsilon_t - \left(x_t \cdot \sum x_t \varepsilon_t\right) / \sum x_t^2. \tag{5.4}$$

Since the residual e_t has a statistical distribution with mean zero, the variance of the distribution is

$$V(e_t) = E(e_t^2), \tag{5.5}$$

which, by using (5.4), equals

$$E\left[\varepsilon_t^2 + \frac{x_t^2 \left(\sum x_t \varepsilon_t\right)^2}{\left(\sum x_t^2\right)^2} - 2 \cdot \frac{x_t \varepsilon_t \left(\sum x_t \varepsilon_t\right)}{\sum x_t^2}\right]. \tag{5.6}$$

Under the assumptions that the errors are serially independent and that the x's are nonstochastic (fixed in repeated samples) we obtain

$$V(e_t) = \sigma_\varepsilon^2 + \frac{x_t^2 \cdot \sigma_\varepsilon^2 \cdot \sum x_t^2}{(\sum x_t^2)^2} - \frac{2x_t^2\sigma_\varepsilon^2}{\sum x_t^2} \tag{5.7}$$

$$= \sigma_\varepsilon^2 \cdot \left\{1 - \frac{x_t^2}{\sum x_t^2}\right\}. \tag{5.8}$$

Realizing that $V(\varepsilon) = \sigma_\varepsilon^2$, we note that the variance of the residuals is not the same as that of error terms; $V(e)$ depends on the values of x:

$$V(e_t) = V(\varepsilon_t) \cdot \left\{1 - \frac{x_t^2}{\sum x_t^2}\right\}. \tag{5.9}$$

If the error terms are homoscedastic and random, the residual corresponding to a given value of x has a statistical distribution with mean zero and variance (5.9). The variance of the residual depends on the value of x, even though the variance of the error term does not. The three-sigma limits for the error term and residuals differ for various values of x, as shown in Figure 5.4. If the researcher interprets the observed behavior of residuals as the behavior of errors, he may reach the wrong conclusion. It is advisable first to draw the expected three-sigma limits for the residuals on the basis of the maximum and the minimum values of the independent variable and on $\sum x_t^2$, before plotting the residuals against an independent variable as a search procedure for locating heteroscedasticity of the error terms.

When $\sum x_t^2$ is very large *compared* to the largest magnitude of observed x, the three-sigma limits for the residuals approach the three-sigma limits for the error terms.

In some empirical work the theory clearly indicates the nature of the variance of the error term. When the theory specifies heteroscedasticity in the error terms then, of course, there is no need to search the residuals. Consider, for example, the case of an investment decision function in the Indian engineering industry (see p. 101 for the notation). For each firm, let the investment decision function be

$$I_j = \beta_0 + \beta_1 S_j + \beta_2 P_j + \varepsilon_j, \tag{5.10}$$

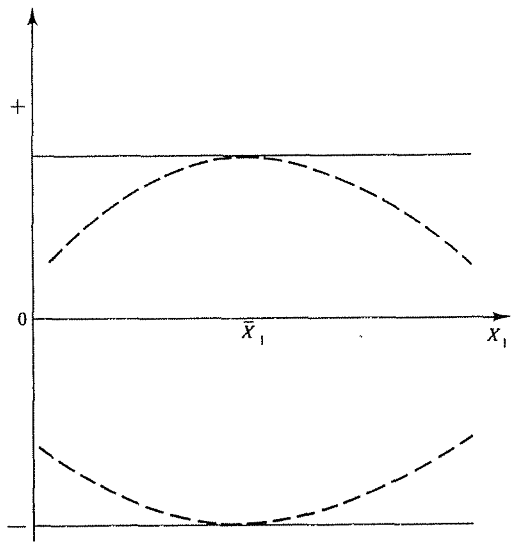


Figure 5.4. Three-Sigma Limits for Error Term and Residuals

where j denotes the jth firm. Let us assume that the variance of the error term for each firm is the same, σ^2.

When data are available for each firm then, of course, there is no problem of heteroscedasticity. But the data in each year relate to aggregates of several numbers of firms, and the number is not the same for all the time periods under investigation. For example there were 54 firms in 1950 and 131 in 1965. Since the data correspond to aggregates, we may express equation (5.10) in terms of the aggregates as

$$\sum_j I_j = \sum_j \beta_0 + \beta_1 \sum_j S_j + \beta_2 \sum_j P_j + \sum_j \varepsilon_j. \tag{5.11}$$

Let N_t be the number of firms for the year t. When the aggregates corresponding to year t are denoted by a subscript t, the investment decision function in terms of the aggregates may be written as

$$I_t = \beta_0 N_t + \beta_1 S_t + \beta_2 P_t + \varepsilon_t. \tag{5.12}$$

Even though equation (5.10) is homoscedastic, equation (5.12) is not. According to the Gauss-Markov theorem, estimation of (5.12) by ordinary least squares does not yield the minimum-variance unbiased estimates of the parameters (β's). However, by a suitable transformation of the variables we may reduce equation (5.12) to a Gauss-Markov case. Consider the variance of the error term ε_t:

$$V(\varepsilon_t) = V(\sum \varepsilon_j) = N_t \cdot \sigma^2, \tag{5.13}$$

since the error terms for each firm are independent of the errors in the other firms.

Suppose we define a new error term ε_t^* as

$$\varepsilon_t^* = \varepsilon_t / \sqrt{N_t}. \tag{5.14}$$

Its variance is

$$V(\varepsilon_t^*) = \sigma^2. \tag{5.15}$$

The transformed error term ε^* has the same variance for all t. Therefore, if we can express equation (5.12) in terms of ε^* the Gauss-Markov theorem holds and we obtain the minimum-variance unbiased estimates of β's by using ordinary least squares. Suppose we divide equation (5.12) by $\sqrt{N_t}$:

$$\frac{I_t}{\sqrt{N_t}} = \beta_0 \frac{N_t}{\sqrt{N_t}} + \beta_1 \frac{S_t}{\sqrt{N_t}} + \beta_2 \frac{P_t}{\sqrt{N_t}} + \frac{\varepsilon_t}{\sqrt{N_t}}. \tag{5.16}$$

By rewriting, (5.16) becomes

$$\frac{I_t}{\sqrt{N_t}} = \beta_0 \sqrt{N_t} + \beta_1 \frac{S_t}{\sqrt{N_t}} + \beta_2 \frac{P_t}{\sqrt{N_t}} + \varepsilon_t^*. \tag{5.17}$$

Equation (5.17) satisfies the Gauss-Markov conditions, hence ordinary least squares estimation of (5.17) provides best linear unbiased estimates.

Since the parameters of (5.12) are the same as those of (5.17), the $\hat{\beta}_0$ from (5.17) is the estimate of the constant term in equation (5.12).

The researcher may note that the general practice for this aggregation problem is to formulate equation (5.10) as though it corresponds to aggregates and then to divide by $\sqrt{N_t}$ to correct for heteroscedasticity. This is a bad practice; even worse, it gives wrong answers.

The investment decision function for the Indian engineering industry, adjusted for heteroscedasticity, is estimated as

$$\frac{I_t}{\sqrt{N_t}} = -\underset{(53.37)}{61.36} + \underset{(7.36)}{7.43}\sqrt{N_t} + \underset{(0.019)}{0.076}\left(\frac{S_t}{\sqrt{N_t}}\right) + \underset{(0.437)}{0.036}\left(\frac{P_t}{\sqrt{N_t}}\right) \qquad R^2 = 0.98. \tag{5.18}$$

Given the level of sales, the movements in profits do not seem to influence the movements in investment. Whether we assume heteroscedasticity or not, we are reaching the same conclusions, for the coefficient of P_t in (4.57) was insignificant also.

In estimating (5.18) we introduced a constant term even though the theoretical specification (5.17) does not provide for it. The constant term in this context has no operational significance. It is there only to allow flexibility in the estimated equation and to simplify the interpretation of the summary statistics (R^2 and standard errors). See the discussion on interpretation of the constant term on page 5.

5.5 *Serial Correlation in Residuals*

In Chapter 3 it was shown that when the error terms are serially dependent the estimates by ordinary least squares are not the minimum-variance unbiased estimates of the parameters. We also studied an alternative estimation procedure (generalized least squares) using an estimate of the parameter (ρ) of serial correlation. Since a theory seldom provides unambiguous information on the serial correlation of the error terms, the researcher wants to infer the nature of serial correlation in the errors from analysis of the residuals with the hope of improving the precision of his estimates.

A point often overlooked by researchers is that correcting for serial correlation does not always give "better" results unless the parameter of serial correlation is known, which is rarely the case. Whenever an estimate of the serial

Seelye Rebuttal Exhibit 3

```
#
#This R code performs weighted least squares analysis
#using the software package R.
#
#As with most other statistical package, R includes an
#option to perform a weighted regression analysis
#
#
#The data is from Seelye Exhibit 25, Page 2 of 4

#capture output in file
sink("f:/WLSQ in R/output.lis")

#Size variable for Overhead Conductor (which is the dependent variable
#in the regression analysis).
#The units are in MCM
size <- c(0.01,0.02,0.19,0.24,0.67,1.31,1.38,1.44,
1.6,1.63,1.8,1.85,3.57,4,0.86,6.95,7,7.5,4,16,16.55)

#Cost variable for Overhead Conductor (average cost per conductor types)
cost<- c(6.53,16.51,26.24,41.74,66.36,83.69,105.6,133.1,167.8,211.6,266,
266.8,300,350,397,500,556,750,795,954,1000)

#Number of units (feet of conductor) used as the weight in the regression
analysis
units <-
c(1515,1212,18421,89519,971519,88940,39898,713507,1954687,112230,288794,
20263,9557,769,265460,7511,919,766,113204,100,331)


#Standard weighted regression model
res <- lm(size ~ cost, weight=units)

res



#In the above, lines beginning with "#" are comments; otherwise the line
is code.
```

```
Call:
lm(formula = size ~ cost, weights = units)

Coefficients:
(Intercept)         cost
   0.756973     0.003659
```

Seelye Rebuttal Exhibit 4

Least-Squares Regression Based on Underlying Individual Unit Cost Data

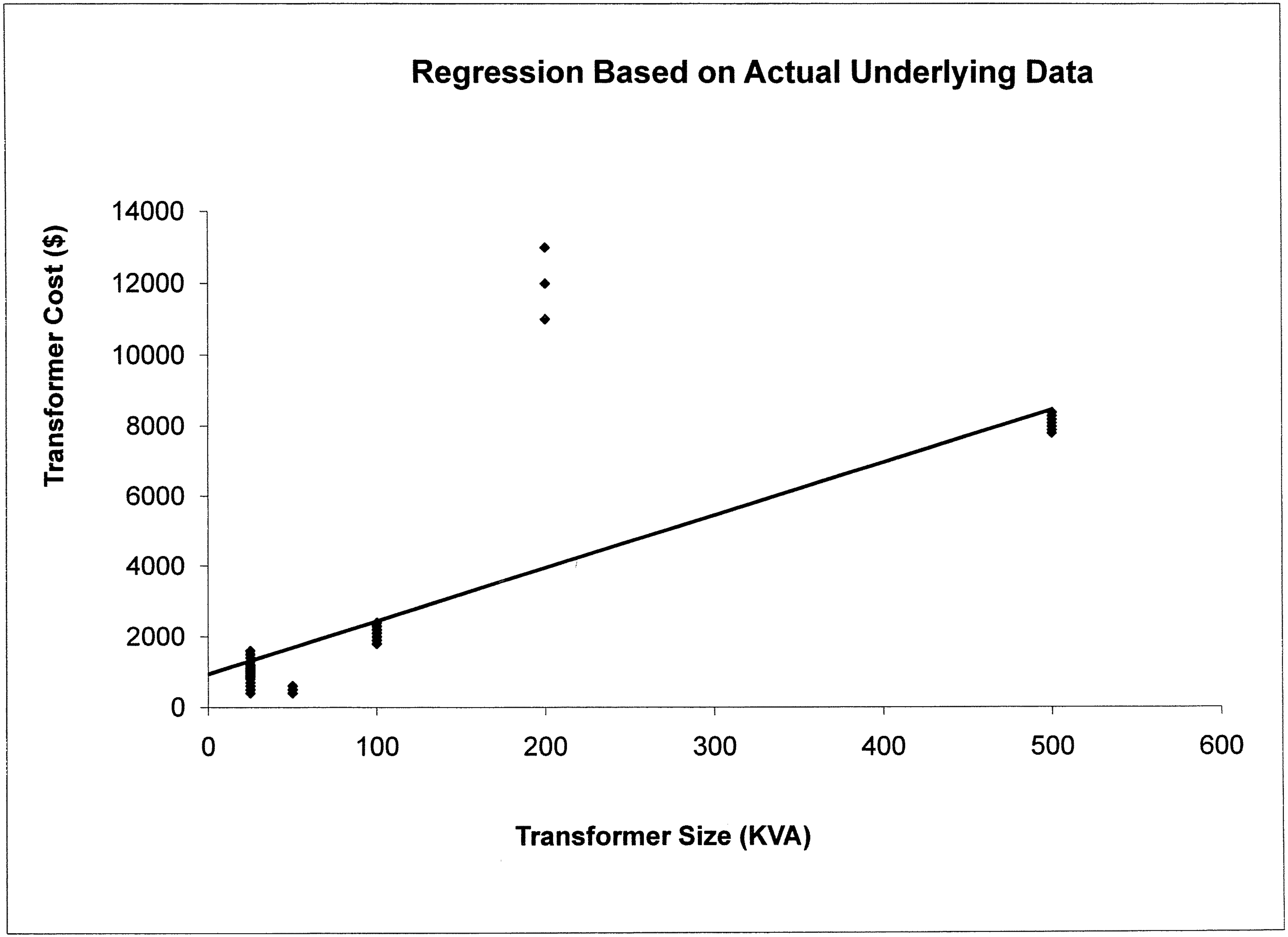
	Cost (y)	Size (x)
1	400	25
2	500	25
3	600	25
4	700	25
5	800	25
6	850	25
7	900	25
8	950	25
9	950	25
10	1000	25
11	1000	25
12	1050	25
13	1050	25
14	1100	25
15	1150	25
16	1200	25
17	1300	25
18	1400	25
19	1500	25
20	1600	25
21	400	50
22	500	50
23	600	50
24	1800	100
25	1800	100
26	1900	100
27	1900	100
28	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

Least-Squares Regression Based on Underlying Individual Unit Cost Data

	Cost (y)	Size (x)
41	2300	100
42	2400	100
43	2400	100
44	11000	200
45	12000	200
46	13000	200
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 5

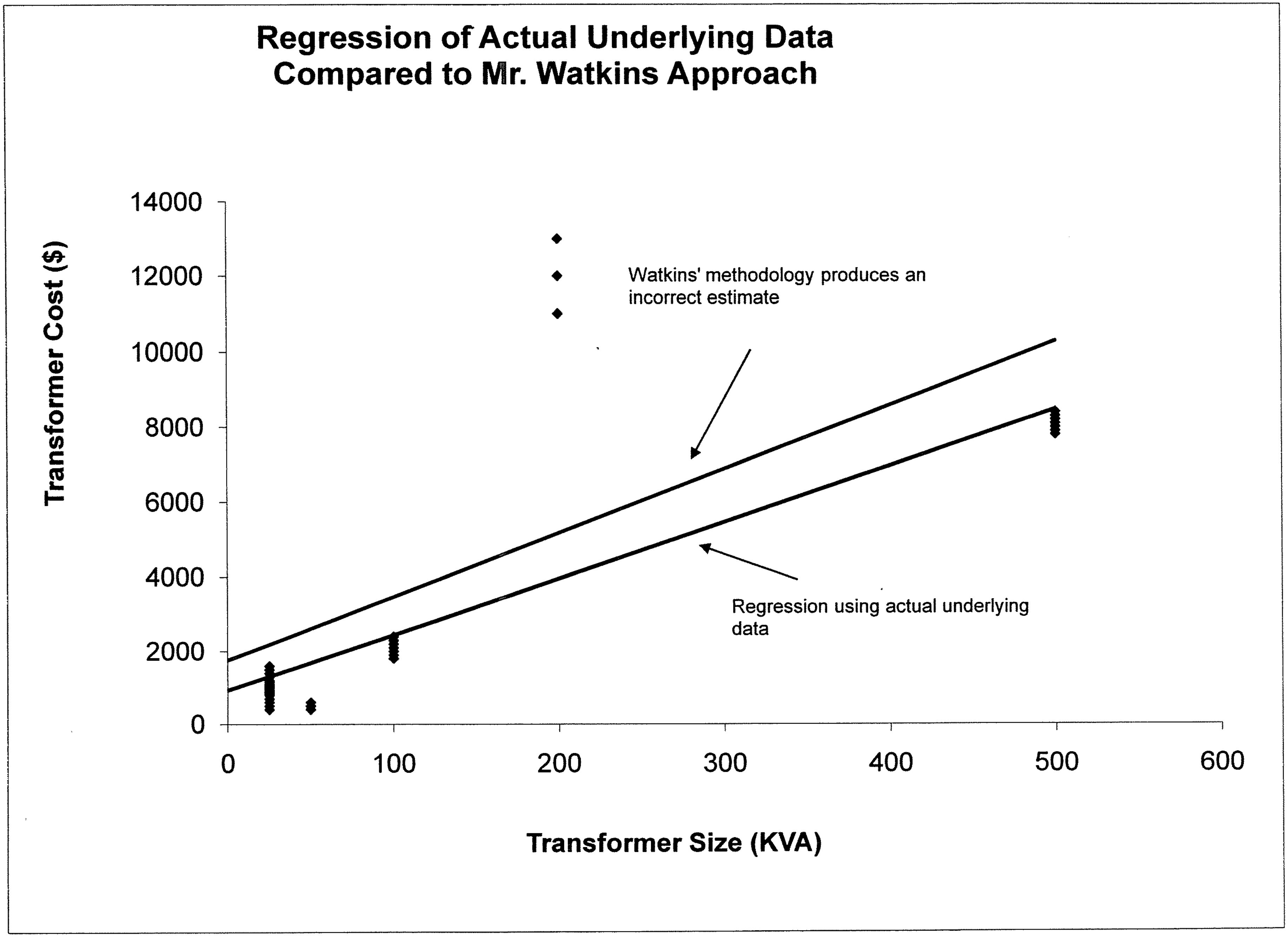
Watkins' Methodology
Unweighted Least-Squares Regression Applied to Summary Data

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
Watkins' methodology produces an incorrect estimate
Regression using actual underlying data
0
100
200
300
400
500
600
Transformer Size (KVA)

Seelye Rebuttal Exhibit 6

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 7

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)	$55,361,707	<<----Left Out By Watkins	
364-365 Overhead Lines - Secondary (Customer Cost)	$17,720,396	<<----Left Out By Watkins	
366-367 Underground Lines - Primary (Customer Cost)	$29,056,141	<<----Left Out By Watkins	
366-367 Underground Lines - Secondary (Customer Cost)	$228,494	<<----Left Out By Watkins	
368 Transformers - Power Pool (Customer Cost)	$50,061,890	<<----Left Out By Watkins	
369 Services	$22,105,235		
370 Meters	$30,569,462		
Total Gross Plant	$205,103,325		
Depreciation Reserve			
364-365 Overhead Lines - Primary (Customer Cost)	$25,892,696	<<----Left Out By Watkins	
364-365 Overhead Lines - Secondary (Customer Cost)	$8,287,838	<<----Left Out By Watkins	
366-367 Underground Lines - Primary (Customer Cost)	$13,589,571	<<----Left Out By Watkins	
366-367 Underground Lines - Secondary (Customer Cost)	$106,867	<<----Left Out By Watkins	
368 Transformers - Power Pool (Customer Cost)	$23,413,970	<<----Left Out By Watkins	
369 Services	$10,338,629		
370 Meters	$14,297,352		
Total Depreciation Reserve	$95,926,922		
Total Net Plant	$109,176,403		
Working Capital Assets			
Cash Working Capital - Operation and Maintenance Expenses	$3,002,178		0.1079
Materials and Supplies	$3,606,353		0.1079
Prepayments	$148,852		0.1079
Mill Creek Ash Dredging Project	$41,759		0.1079
Sub-total	$6,799,142		
Customer Advances			
Customer Advances	$117,928		0.1079
Sub-total	$117,928		
Other Items			
Total Accumulated Deferred Income Tax	$15,570,952		0.1079
Sub-total	$15,570,952		
TOTAL RATE BASE	$100,286,666		
Operation & Maintenance Expenses			
Distribution Expense - Operating			
580 Operation Supervision & Engineering	$566,613	<<----Left Out By Watkins	
581 Load Dispatching	$78,275	<<----Left Out By Watkins	
582 Station Expense	$205,683	<<----Left Out By Watkins	
583 Overhead Lines Expense	-$485,718	<<----Left Out By Watkins	
584 Underground Lines Expense	$54,240	<<----Left Out By Watkins	
586 Meter Expense	$5,058,958		
588 Misc Distribution Expense	$686,789	<<----Left Out By Watkins	
589 Rents	$3,421	<<----Left Out By Watkins	
590 Maintenance Supervision & Engineering	$1,479	<<----Left Out By Watkins	
591 Structures	$156,912	<<----Left Out By Watkins	
592 Maintenance Structures & Equipment	$195,043	<<----Left Out By Watkins	
593 Maintenanceof Overhead Lines	-$1,198,089	<<----Left Out By Watkins	
594 Maintenance of Underground Lines	$265,838	<<----Left Out By Watkins	
595 Maintenance of Line Transformers	-$193,286	<<----Left Out By Watkins	
598 Misc Distribution Expense	$70,117	<<----Left Out By Watkins	
Sub-total	$5,411,926		
Customer Accounts Expense			
901 Supervision/Customer Accts	$633,950	<<----Left Out By Watkins	
902 Meter Reading Expense	$1,673,264		
903 Records & Collections	$4,206,469		
904 Uncollectible Accounts	$1,904,262	<<----Left Out By Watkins	
905 Misc Customer Accounts	$300,266	<<----Left Out By Watkins	
Sub-total	$8,718,211		

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	
	Customer Service & Information Expense		
907	Supervision	$94,772	**<<----Left Out By Watkins**
908	Customer Assistance Expense	$5,078,413	**<<----Left Out By Watkins**
909	Informationational & Instruc	$125,086	**<<----Left Out By Watkins**
910	Misc Customer Service	$1,844,538	**<<----Left Out By Watkins**
912	Demonstration & Selling Exp	$6,301	**<<----Left Out By Watkins**
913	Advertising Expense	$33,962	**<<----Left Out By Watkins**
	Sub-total	$7,183,072	
	General Expenses		
920	Admin & General Salaries	$518,093	**<<----Left Out By Watkins**
921	Office Supplies & Expenses	$159,008	**<<----Left Out By Watkins**
922	Administrative Expenses Transferred	-$82,570	**<<----Left Out By Watkins**
923	Outside Services Employed	$197,304	**<<----Left Out By Watkins**
924	Property Insurance	$114,842	**<<----Left Out By Watkins**
925	Injuries & Damages - Insurance	$62,890	**<<----Left Out By Watkins**
926	Employee Benefits	$1,294,279	**<<----Left Out By Watkins**
927	Franchise Requirements	$41,357	**<<----Left Out By Watkins**
928	Regulatory Commission Fees	$38,466	**<<----Left Out By Watkins**
929	Duplicate Charges - Cr	-$1,003	**<<----Left Out By Watkins**
930	Miscellaneous General Expense	$59,407	**<<----Left Out By Watkins**
931	Rents & Leases	$47,849	**<<----Left Out By Watkins**
935	Maintenance of General Plant	$254,287	**<<----Left Out By Watkins**
	Sub-total	$2,704,209	
	Total O & M Expenses	$24,017,418	
Depreciation Expense			
364-365	Distribution Primary Lines	$6,932,099	**<<----Left Out By Watkins**
366-367	Distribution Secondary Lines	$1,598,481	**<<----Left Out By Watkins**
369	Services	$631,960	
370	Meters	$873,940	
	Total Depreciation Expense	$10,036,480	

Revenue Requirement

Interest	$2,325,457				
Equity return	$6,762,277				
Income Tax	$4,083,396				
Revenue For Return	13,171,131		PCT	Cost	WGHT Cost
		Debt	46.14%	4.61%	2.13%
O & M Expenses	$24,017,418	Common	53.86%	11.50%	6.19%
Depreciation Expense	$10,036,480	Total	100.00%		8.32%
Total Customer Revenue Requirement	$47,225,029				
Number of Bills	4,194,562				
Monthly Cost	$11.26				

Seelye Rebuttal Exhibit 8

Index	Series A	Series B	Aggregated Value Series A & B
1	70	62	132
2	2	76	78
3	75	49	124
4	26	75	101
5	56	66	122
6	46	10	56
7	77	5	82
8	99	68	167
9	34	33	67
10	35	51	86
11	67	95	162
12	72	44	116
13	95	20	115
14	92	75	167
15	25	81	106
16	96	13	109
17	72	16	88
18	86	74	160
19	56	29	85
20	21	66	87
21	85	57	142
22	69	43	112
23	20	72	92
24	79	80	159
	99	95	167
		Sum of Maximums 194	Maximum of Sums 167

Automatic Savings Under Aggregated Demands 27

Seelye Rebuttal Exhibit 9

		Store A	Store B	Store A + Store B
1/1/2010				
	0:15	326.40	1401.60	1728.00
	0:30	320.64	1420.80	1741.44
	0:45	307.20	1392.00	1699.20
	1:00	295.68	1420.80	1716.48
	1:15	314.88	1392.00	1706.88
	1:30	309.12	1286.40	1595.52
	1:45	309.12	1296.00	1605.12
	2:00	297.60	1334.40	1632.00
	2:15	316.80	1324.80	1641.60
	2:30	322.56	1305.60	1628.16
	2:45	324.48	1296.00	1620.48
	3:00	324.48	1305.60	1630.08
	3:15	337.92	1305.60	1643.52
	3:30	314.88	1315.20	1630.08
	3:45	318.72	1305.60	1624.32
	4:00	301.44	1315.20	1616.64
	4:15	312.96	1296.00	1608.96
	4:30	318.72	1315.20	1633.92
	4:45	309.12	1334.40	1643.52
	5:00	303.36	1315.20	1618.56
	5:15	303.36	1305.60	1608.96
	5:30	303.36	1372.80	1676.16
	5:45	305.28	1459.20	1764.48
	6:00	305.28	1449.60	1754.88
	6:15	314.88	1440.00	1754.88
	6:30	343.68	1353.60	1697.28
	6:45	311.04	1440.00	1751.04
	7:00	345.60	1363.20	1708.80
	7:15	391.68	1411.20	1802.88
	7:30	385.92	1411.20	1797.12
	7:45	387.84	1363.20	1751.04
	8:00	393.60	1315.20	1708.80
	8:15	366.72	1296.00	1662.72
	8:30	368.64	1286.40	1655.04
	8:45	372.48	1257.60	1630.08
	9:00	357.12	1257.60	1614.72
	9:15	364.80	1248.00	1612.80
	9:30	366.72	1238.40	1605.12
	9:45	366.72	1238.40	1605.12
	10:00	372.48	1286.40	1658.88
	10:15	378.24	1257.60	1635.84
	10:30	368.64	1248.00	1616.64
	10:45	359.04	1267.20	1626.24
	11:00	384.00	1238.40	1622.40
	11:15	360.96	1257.60	1618.56
	11:30	366.72	1228.80	1595.52
	11:45	372.48	1228.80	1601.28
	12:00	368.64	1228.80	1597.44
	12:15	351.36	1219.20	1570.56
	12:30	349.44	1228.80	1578.24
	12:45	362.88	1219.20	1582.08
	13:00	389.76	1257.60	1647.36
	13:15	376.32	1238.40	1614.72
	13:30	384.00	1219.20	1603.20
	13:45	380.16	1238.40	1618.56
	14:00	368.64	1267.20	1635.84
	14:15	360.96	1209.60	1570.56
	14:30	380.16	1190.40	1570.56
	14:45	380.16	1238.40	1618.56
	15:00	360.96	1228.80	1589.76
	15:15	370.56	1296.00	1666.56
	15:30	382.08	1344.00	1726.08
	15:45	362.88	1315.20	1678.08
	16:00	355.20	1315.20	1670.40
	16:15	376.32	1305.60	1681.92
	16:30	374.40	1334.40	1708.80
	16:45	355.20	1344.00	1699.20
	17:00	359.04	1382.40	1741.44
	17:15	360.96	1305.60	1666.56
	17:30	372.48	1382.40	1754.88
	17:45	403.20	1286.40	1689.60
	18:00	380.16	1478.40	1858.56
	18:15	387.84	1574.40	1962.24

		Store A	Store B	Store A + Store B
	18:30	380.16	1584.00	1964.16
	18:45	384.00	1545.60	1929.60
	19:00	374.40	1641.60	2016.00
	19:15	387.84	1641.60	2029.44
	19:30	368.64	1699.20	2067.84
	19:45	395.52	1737.60	2133.12
	20:00	384.00	1689.60	2073.60
	20:15	368.64	1708.80	2077.44
	20:30	368.64	1689.60	2058.24
	20:45	370.56	1747.20	2117.76
	21:00	376.32	1718.40	2094.72
	21:15	355.20	1699.20	2054.40
	21:30	355.20	1747.20	2102.40
	21:45	362.88	1737.60	2100.48
	22:00	355.20	1795.20	2150.40
	22:15	347.52	1795.20	2142.72
	22:30	351.36	1718.40	2069.76
	22:45	347.52	1680.00	2027.52
	23:00	326.40	1699.20	2025.60
	23:15	332.16	1660.80	1992.96
	23:30	341.76	1660.80	2002.56
	23:45	336.00	1689.60	2025.60
1/2/2010	0:00	345.60	1718.40	2064.00
	0:15	322.56	1728.00	2050.56
	0:30	318.72	1728.00	2046.72
	0:45	309.12	1756.80	2065.92
	1:00	299.52	1708.80	2008.32
	1:15	314.88	1795.20	2110.08
	1:30	307.20	1833.60	2140.80
	1:45	307.20	1708.80	2016.00
	2:00	299.52	1747.20	2046.72
	2:15	320.64	1804.80	2125.44
	2:30	328.32	1776.00	2104.32
	2:45	326.40	1785.60	2112.00
	3:00	326.40	1728.00	2054.40
	3:15	332.16	1689.60	2021.76
	3:30	311.04	1708.80	2019.84
	3:45	311.04	1680.00	1991.04
	4:00	303.36	1680.00	1983.36
	4:15	312.96	1680.00	1992.96
	4:30	326.40	1603.20	1929.60
	4:45	309.12	1564.80	1873.92
	5:00	303.36	1555.20	1858.56
	5:15	312.96	1555.20	1868.16
	5:30	309.12	1555.20	1864.32
	5:45	311.04	1680.00	1991.04
	6:00	303.36	1612.80	1916.16
	6:15	341.76	1651.20	1992.96
	6:30	318.72	1593.60	1912.32
	6:45	318.72	1708.80	2027.52
	7:00	316.80	1651.20	1968.00
	7:15	389.76	1737.60	2127.36
	7:30	384.00	1814.40	2198.40
	7:45	391.68	1776.00	2167.68
	8:00	378.24	1843.20	2221.44
	8:15	382.08	1862.40	2244.48
	8:30	376.32	1804.80	2181.12
	8:45	366.72	1795.20	2161.92
	9:00	374.40	1814.40	2188.80
	9:15	360.96	1900.80	2261.76
	9:30	366.72	1862.40	2229.12
	9:45	364.80	1891.20	2256.00
	10:00	359.04	1948.80	2307.84
	10:15	376.32	1900.80	2277.12
	10:30	393.60	1939.20	2332.80
	10:45	422.40	1881.60	2304.00
	11:00	372.48	1977.60	2350.08
	11:15	372.48	1958.40	2330.88
	11:30	382.08	1939.20	2321.28
	11:45	374.40	1929.60	2304.00
	12:00	370.56	1891.20	2261.76
	12:15	385.92	2025.60	2411.52
	12:30	378.24	1910.40	2288.64
	12:45	370.56	1948.80	2319.36

		Store A	Store B	Store A + Store B
	13:00	399.36	1910.40	2309.76
	13:15	410.88	1958.40	2369.28
	13:30	389.76	2006.40	2396.16
	13:45	387.84	1920.00	2307.84
	14:00	364.80	1920.00	2284.80
	14:15	372.48	1814.40	2186.88
	14:30	359.04	1776.00	2135.04
	14:45	382.08	1872.00	2254.08
	15:00	380.16	1804.80	2184.96
	15:15	378.24	1900.80	2279.04
	15:30	382.08	1881.60	2263.68
	15:45	391.68	1891.20	2282.88
	16:00	384.00	1920.00	2304.00
	16:15	384.00	1920.00	2304.00
	16:30	382.08	2025.60	2407.68
	16:45	374.40	1852.80	2227.20
	17:00	372.48	1958.40	2330.88
	17:15	374.40	1785.60	2160.00
	17:30	364.80	1756.80	2121.60
	17:45	380.16	1612.80	1992.96
	18:00	399.36	1852.80	2252.16
	18:15	401.28	1862.40	2263.68
	18:30	408.96	1785.60	2194.56
	18:45	399.36	1833.60	2232.96
	19:00	393.60	1862.40	2256.00
	19:15	407.04	1833.60	2240.64
	19:30	408.96	1891.20	2300.16
	19:45	393.60	1900.80	2294.40
	20:00	399.36	1852.80	2252.16
	20:15	380.16	1824.00	2204.16
	20:30	385.92	1833.60	2219.52
	20:45	384.00	1862.40	2246.40
	21:00	395.52	1795.20	2190.72
	21:15	368.64	1872.00	2240.64
	21:30	360.96	1804.80	2165.76
	21:45	368.64	1881.60	2250.24
	22:00	360.96	1881.60	2242.56
	22:15	355.20	1881.60	2236.80
	22:30	357.12	1891.20	2248.32
	22:45	347.52	1737.60	2085.12
	23:00	341.76	1795.20	2136.96
	23:15	337.92	1756.80	2094.72
	23:30	341.76	1699.20	2040.96
	23:45	351.36	1718.40	2069.76
1/3/2010	0:00	353.28	1747.20	2100.48
	0:15	318.72	1737.60	2056.32
	0:30	320.64	1747.20	2067.84
	0:45	326.40	1728.00	2054.40
	1:00	305.28	1708.80	2014.08
	1:15	326.40	1747.20	2073.60
	1:30	324.48	1747.20	2071.68
	1:45	303.36	1660.80	1964.16
	2:00	305.28	1708.80	2014.08
	2:15	351.36	1833.60	2184.96
	2:30	328.32	1776.00	2104.32
	2:45	337.92	1747.20	2085.12
	3:00	347.52	1795.20	2142.72
	3:15	359.04	1776.00	2135.04
	3:30	320.64	1728.00	2048.64
	3:45	324.48	1747.20	2071.68
	4:00	312.96	1785.60	2098.56
	4:15	316.80	1776.00	2092.80
	4:30	316.80	1843.20	2160.00
	4:45	305.28	1747.20	2052.48
	5:00	301.44	1699.20	2000.64
	5:15	316.80	1718.40	2035.20
	5:30	305.28	1737.60	2042.88
	5:45	303.36	1737.60	2040.96
	6:00	303.36	1737.60	2040.96
	6:15	320.64	1660.80	1981.44
	6:30	343.68	1603.20	1946.88
	6:45	320.64	1632.00	1952.64
	7:00	316.80	1603.20	1920.00
	7:15	384.00	1708.80	2092.80

		Store A	Store B	Store A + Store B
	7:30	393.60	1699.20	2092.80
	7:45	391.68	1718.40	2110.08
	8:00	385.92	1766.40	2152.32
	8:15	372.48	1776.00	2148.48
	8:30	391.68	1737.60	2129.28
	8:45	391.68	1756.80	2148.48
	9:00	395.52	1747.20	2142.72
	9:15	399.36	1795.20	2194.56
	9:30	393.60	1699.20	2092.80
	9:45	385.92	1747.20	2133.12
	10:00	372.48	1718.40	2090.88
	10:15	357.12	1737.60	2094.72
	10:30	382.08	1795.20	2177.28
	10:45	384.00	1756.80	2140.80
	11:00	353.28	1814.40	2167.68
	11:15	364.80	1795.20	2160.00
	11:30	366.72	1862.40	2229.12
	11:45	374.40	1814.40	2188.80
	12:00	374.40	1843.20	2217.60
	12:15	384.00	1891.20	2275.20
	12:30	395.52	1843.20	2238.72
	12:45	384.00	1891.20	2275.20
	13:00	378.24	1766.40	2144.64
	13:15	378.24	1824.00	2202.24
	13:30	387.84	1843.20	2231.04
	13:45	397.44	1785.60	2183.04
	14:00	393.60	1804.80	2198.40
	14:15	372.48	1776.00	2148.48
	14:30	384.00	1680.00	2064.00
	14:45	376.32	1824.00	2200.32
	15:00	397.44	1776.00	2173.44
	15:15	380.16	1910.40	2290.56
	15:30	387.84	1891.20	2279.04
	15:45	380.16	1872.00	2252.16
	16:00	385.92	1920.00	2305.92
	16:15	405.12	1833.60	2238.72
	16:30	420.48	1977.60	2398.08
	16:45	408.96	1900.80	2309.76
	17:00	391.68	1881.60	2273.28
	17:15	395.52	1756.80	2152.32
	17:30	405.12	1718.40	2123.52
	17:45	422.40	1584.00	2006.40
	18:00	401.28	1737.60	2138.88
	18:15	414.72	1747.20	2161.92
	18:30	401.28	1680.00	2081.28
	18:45	408.96	1699.20	2108.16
	19:00	395.52	1737.60	2133.12
	19:15	389.76	1660.80	2050.56
	19:30	399.36	1747.20	2146.56
	19:45	389.76	1776.00	2165.76
	20:00	393.60	1756.80	2150.40
	20:15	380.16	1776.00	2156.16
	20:30	397.44	1718.40	2115.84
	20:45	391.68	1776.00	2167.68
	21:00	393.60	1718.40	2112.00
	21:15	374.40	1660.80	2035.20
	21:30	376.32	1680.00	2056.32
	21:45	378.24	1747.20	2125.44
	22:00	362.88	1756.80	2119.68
	22:15	368.64	1718.40	2087.04
	22:30	376.32	1776.00	2152.32
	22:45	353.28	1737.60	2090.88
	23:00	351.36	1718.40	2069.76
	23:15	336.00	1737.60	2073.60
	23:30	359.04	1660.80	2019.84
	23:45	362.88	1804.80	2167.68
1/4/2010	0:00	366.72	1718.40	2085.12
	0:15	336.00	1766.40	2102.40
	0:30	332.16	1747.20	2079.36
	0:45	322.56	1756.80	2079.36
	1:00	314.88	1756.80	2071.68
	1:15	326.40	1718.40	2044.80
	1:30	326.40	1804.80	2131.20
	1:45	318.72	1660.80	1979.52

	Store A	Store B	Store A + Store B
2:00	311.04	1776.00	2087.04
2:15	326.40	1708.80	2035.20
2:30	334.08	1747.20	2081.28
2:45	336.00	1747.20	2083.20
3:00	343.68	1737.60	2081.28
3:15	347.52	1718.40	2065.92
3:30	334.08	1612.80	1946.88
3:45	324.48	1632.00	1956.48
4:00	328.32	1593.60	1921.92
4:15	353.28	1516.80	1870.08
4:30	380.16	1516.80	1896.96
4:45	345.60	1478.40	1824.00
5:00	339.84	1420.80	1760.64
5:15	334.08	1420.80	1754.88
5:30	341.76	1478.40	1820.16
5:45	343.68	1516.80	1860.48
6:00	341.76	1526.40	1868.16
6:15	347.52	1526.40	1873.92
6:30	359.04	1488.00	1847.04
6:45	353.28	1660.80	2014.08
7:00	347.52	1612.80	1960.32
7:15	432.00	1756.80	2188.80
7:30	418.56	1766.40	2184.96
7:45	422.40	1660.80	2083.20
8:00	401.28	1776.00	2177.28
8:15	414.72	1699.20	2113.92
8:30	414.72	1699.20	2113.92
8:45	410.88	1747.20	2158.08
9:00	418.56	1641.60	2060.16
9:15	416.64	1747.20	2163.84
9:30	391.68	1670.40	2062.08
9:45	382.08	1670.40	2052.48
10:00	397.44	1689.60	2087.04
10:15	385.92	1660.80	2046.72
10:30	395.52	1776.00	2171.52
10:45	385.92	1737.60	2123.52
11:00	385.92	1804.80	2190.72
11:15	387.84	1795.20	2183.04
11:30	387.84	1776.00	2163.84
11:45	389.76	1843.20	2232.96
12:00	407.04	1756.80	2163.84
12:15	399.36	1824.00	2223.36
12:30	412.80	1795.20	2208.00
12:45	426.24	1795.20	2221.44
13:00	391.68	1852.80	2244.48
13:15	391.68	1852.80	2244.48
13:30	416.64	1814.40	2231.04
13:45	422.40	1862.40	2284.80
14:00	393.60	1756.80	2150.40
14:15	403.20	1756.80	2160.00
14:30	449.28	1680.00	2129.28
14:45	460.80	1737.60	2198.40
15:00	445.44	1737.60	2183.04
15:15	399.36	1852.80	2252.16
15:30	407.04	1795.20	2202.24
15:45	395.52	1785.60	2181.12
16:00	403.20	1728.00	2131.20
16:15	410.88	1680.00	2090.88
16:30	426.24	1756.80	2183.04
16:45	449.28	1603.20	2052.48
17:00	432.00	1670.40	2102.40
17:15	432.00	1593.60	2025.60
17:30	426.24	1603.20	2029.44
17:45	433.92	1526.40	1960.32
18:00	437.76	1593.60	2031.36
18:15	430.08	1660.80	2090.88
18:30	403.20	1564.80	1968.00
18:45	426.24	1660.80	2087.04
19:00	412.80	1612.80	2025.60
19:15	410.88	1612.80	2023.68
19:30	412.80	1708.80	2121.60
19:45	422.40	1680.00	2102.40
20:00	420.48	1747.20	2167.68
20:15	401.28	1641.60	2042.88

		Store A	Store B	Store A + Store B
	20:30	393.60	1766.40	2160.00
	20:45	387.84	1699.20	2087.04
	21:00	397.44	1747.20	2144.64
	21:15	391.68	1737.60	2129.28
	21:30	395.52	1728.00	2123.52
	21:45	393.60	1776.00	2169.60
	22:00	385.92	1776.00	2161.92
	22:15	397.44	1689.60	2087.04
	22:30	387.84	1766.40	2154.24
	22:45	380.16	1670.40	2050.56
	23:00	362.88	1680.00	2042.88
	23:15	370.56	1689.60	2060.16
	23:30	370.56	1603.20	1973.76
	23:45	366.72	1689.60	2056.32
1/5/2010	0:00	370.56	1689.60	2060.16
	0:15	341.76	1689.60	2031.36
	0:30	334.08	1708.80	2042.88
	0:45	322.56	1718.40	2040.96
	1:00	322.56	1718.40	2040.96
	1:15	330.24	1718.40	2048.64
	1:30	332.16	1785.60	2117.76
	1:45	316.80	1699.20	2016.00
	2:00	314.88	1756.80	2071.68
	2:15	336.00	1776.00	2112.00
	2:30	349.44	1718.40	2067.84
	2:45	345.60	1747.20	2092.80
	3:00	347.52	1747.20	2094.72
	3:15	351.36	1747.20	2098.56
	3:30	334.08	1785.60	2119.68
	3:45	322.56	1708.80	2031.36
	4:00	324.48	1632.00	1956.48
	4:15	324.48	1622.40	1946.88
	4:30	355.20	1612.80	1968.00
	4:45	337.92	1545.60	1883.52
	5:00	309.12	1555.20	1864.32
	5:15	312.96	1497.60	1810.56
	5:30	322.56	1526.40	1848.96
	5:45	326.40	1593.60	1920.00
	6:00	324.48	1564.80	1889.28
	6:15	334.08	1516.80	1850.88
	6:30	351.36	1555.20	1906.56
	6:45	324.48	1622.40	1946.88
	7:00	334.08	1641.60	1975.68
	7:15	397.44	1660.80	2058.24
	7:30	432.00	1737.60	2169.60
	7:45	408.96	1699.20	2108.16
	8:00	410.88	1776.00	2186.88
	8:15	412.80	1737.60	2150.40
	8:30	422.40	1804.80	2227.20
	8:45	399.36	1728.00	2127.36
	9:00	378.24	1680.00	2058.24
	9:15	372.48	1785.60	2158.08
	9:30	397.44	1680.00	2077.44
	9:45	368.64	1756.80	2125.44
	10:00	364.80	1804.80	2169.60
	10:15	370.56	1785.60	2156.16
	10:30	370.56	1872.00	2242.56
	10:45	378.24	1872.00	2250.24
	11:00	385.92	1852.80	2238.72
	11:15	362.88	1929.60	2292.48
	11:30	359.04	1891.20	2250.24
	11:45	362.88	1814.40	2177.28
	12:00	364.80	1852.80	2217.60
	12:15	376.32	1881.60	2257.92
	12:30	395.52	1852.80	2248.32
	12:45	382.08	1804.80	2186.88
	13:00	366.72	1872.00	2238.72
	13:15	364.80	1824.00	2188.80
	13:30	378.24	1872.00	2250.24
	13:45	401.28	1910.40	2311.68
	14:00	387.84	1795.20	2183.04
	14:15	389.76	1756.80	2146.56
	14:30	405.12	1833.60	2238.72
	14:45	382.08	1785.60	2167.68

		Store A	Store B	Store A + Store B
	15:00	399.36	1776.00	2175.36
	15:15	395.52	1833.60	2229.12
	15:30	408.96	1795.20	2204.16
	15:45	410.88	1862.40	2273.28
	16:00	368.64	1776.00	2144.64
	16:15	382.08	1785.60	2167.68
	16:30	370.56	1804.80	2175.36
	16:45	364.80	1708.80	2073.60
	17:00	393.60	1776.00	2169.60
	17:15	399.36	1670.40	2069.76
	17:30	412.80	1632.00	2044.80
	17:45	416.64	1651.20	2067.84
	18:00	387.84	1632.00	2019.84
	18:15	407.04	1708.80	2115.84
	18:30	405.12	1603.20	2008.32
	18:45	405.12	1670.40	2075.52
	19:00	395.52	1680.00	2075.52
	19:15	384.00	1689.60	2073.60
	19:30	397.44	1737.60	2135.04
	19:45	405.12	1776.00	2181.12
	20:00	393.60	1718.40	2112.00
	20:15	393.60	1776.00	2169.60
	20:30	395.52	1756.80	2152.32
	20:45	395.52	1737.60	2133.12
	21:00	389.76	1785.60	2175.36
	21:15	368.64	1708.80	2077.44
	21:30	376.32	1824.00	2200.32
	21:45	364.80	1795.20	2160.00
	22:00	359.04	1785.60	2144.64
	22:15	370.56	1785.60	2156.16
	22:30	362.88	1766.40	2129.28
	22:45	374.40	1804.80	2179.20
	23:00	343.68	1737.60	2081.28
	23:15	349.44	1804.80	2154.24
	23:30	347.52	1776.00	2123.52
	23:45	351.36	1718.40	2069.76
1/6/2010	0:00	359.04	1785.60	2144.64
	0:15	330.24	1756.80	2087.04
	0:30	330.24	1756.80	2087.04
	0:45	307.20	1747.20	2054.40
	1:00	312.96	1728.00	2040.96
	1:15	314.88	1795.20	2110.08
	1:30	318.72	1824.00	2142.72
	1:45	309.12	1795.20	2104.32
	2:00	299.52	1756.80	2056.32
	2:15	326.40	1795.20	2121.60
	2:30	334.08	1852.80	2186.88
	2:45	359.04	1718.40	2077.44
	3:00	339.84	1728.00	2067.84
	3:15	341.76	1718.40	2060.16
	3:30	324.48	1718.40	2042.88
	3:45	312.96	1795.20	2108.16
	4:00	314.88	1785.60	2100.48
	4:15	320.64	1833.60	2154.24
	4:30	336.00	1737.60	2073.60
	4:45	305.28	1766.40	2071.68
	5:00	297.60	1689.60	1987.20
	5:15	301.44	1612.80	1914.24
	5:30	309.12	1670.40	1979.52
	5:45	314.88	1641.60	1956.48
	6:00	309.12	1680.00	1989.12
	6:15	318.72	1622.40	1941.12
	6:30	372.48	1564.80	1937.28
	6:45	364.80	1612.80	1977.60
	7:00	330.24	1622.40	1952.64
	7:15	378.24	1680.00	2058.24
	7:30	384.00	1785.60	2169.60
	7:45	391.68	1708.80	2100.48
	8:00	385.92	1747.20	2133.12
	8:15	395.52	1756.80	2152.32
	8:30	414.72	1728.00	2142.72
	8:45	418.56	1785.60	2204.16
	9:00	385.92	1718.40	2104.32
	9:15	374.40	1776.00	2150.40

		Store A	Store B	Store A + Store B
	9:30	370.56	1708.80	2079.36
	9:45	378.24	1699.20	2077.44
	10:00	374.40	1776.00	2150.40
	10:15	372.48	1728.00	2100.48
	10:30	389.76	1824.00	2213.76
	10:45	368.64	1718.40	2087.04
	11:00	360.96	1804.80	2165.76
	11:15	357.12	1814.40	2171.52
	11:30	370.56	1756.80	2127.36
	11:45	364.80	1843.20	2208.00
	12:00	374.40	1814.40	2188.80
	12:15	366.72	1948.80	2315.52
	12:30	391.68	1852.80	2244.48
	12:45	384.00	1785.60	2169.60
	13:00	372.48	1747.20	2119.68
	13:15	380.16	1468.80	1848.96
	13:30	385.92	1584.00	1969.92
	13:45	389.76	1948.80	2338.56
	14:00	382.08	1872.00	2254.08
	14:15	391.68	1852.80	2244.48
	14:30	391.68	1766.40	2158.08
	14:45	403.20	1804.80	2208.00
	15:00	408.96	1708.80	2117.76
	15:15	380.16	1920.00	2300.16
	15:30	397.44	1900.80	2298.24
	15:45	418.56	1891.20	2309.76
	16:00	389.76	2016.00	2405.76
	16:15	391.68	1948.80	2340.48
	16:30	403.20	1987.20	2390.40
	16:45	422.40	1939.20	2361.60
	17:00	420.48	1939.20	2359.68
	17:15	395.52	1929.60	2325.12
	17:30	422.40	1852.80	2275.20
	17:45	414.72	1824.00	2238.72
	18:00	422.40	1728.00	2150.40
	18:15	418.56	1948.80	2367.36
	18:30	420.48	1785.60	2206.08
	18:45	416.64	1785.60	2202.24
	19:00	405.12	1785.60	2190.72
	19:15	403.20	1929.60	2332.80
	19:30	407.04	1920.00	2327.04
	19:45	424.32	1958.40	2382.72
	20:00	405.12	1891.20	2296.32
	20:15	401.28	1891.20	2292.48
	20:30	401.28	1852.80	2254.08
	20:45	399.36	1900.80	2300.16
	21:00	410.88	1843.20	2254.08
	21:15	399.36	1824.00	2223.36
	21:30	374.40	1728.00	2102.40
	21:45	376.32	1910.40	2286.72
	22:00	372.48	1785.60	2158.08
	22:15	368.64	1843.20	2211.84
	22:30	378.24	1824.00	2202.24
	22:45	359.04	1833.60	2192.64
	23:00	357.12	1862.40	2219.52
	23:15	351.36	1824.00	2175.36
	23:30	355.20	1804.80	2160.00
	23:45	359.04	1814.40	2173.44
1/7/2010	0:00	368.64	1843.20	2211.84
	0:15	337.92	1910.40	2248.32
	0:30	334.08	1814.40	2148.48
	0:45	320.64	1852.80	2173.44
	1:00	320.64	1785.60	2106.24
	1:15	343.68	1872.00	2215.68
	1:30	324.48	1843.20	2167.68
	1:45	316.80	1766.40	2083.20
	2:00	318.72	1824.00	2142.72
	2:15	343.68	1814.40	2158.08
	2:30	349.44	1852.80	2202.24
	2:45	345.60	1804.80	2150.40
	3:00	332.16	1814.40	2146.56
	3:15	343.68	1843.20	2186.88
	3:30	330.24	1449.60	1779.84
	3:45	324.48	1027.20	1351.68

	Store A	Store B	Store A + Store B
4:00	320.64	940.80	1261.44
4:15	326.40	912.00	1238.40
4:30	336.00	921.60	1257.60
4:45	311.04	950.40	1261.44
5:00	299.52	931.20	1230.72
5:15	318.72	902.40	1221.12
5:30	360.96	844.80	1205.76
5:45	336.00	835.20	1171.20
6:00	324.48	816.00	1140.48
6:15	324.48	844.80	1169.28
6:30	330.24	835.20	1165.44
6:45	334.08	902.40	1236.48
7:00	326.40	902.40	1228.80
7:15	359.04	912.00	1271.04
7:30	385.92	931.20	1317.12
7:45	385.92	940.80	1326.72
8:00	378.24	969.60	1347.84
8:15	395.52	988.80	1384.32
8:30	408.96	1008.00	1416.96
8:45	420.48	1008.00	1428.48
9:00	408.96	998.40	1407.36
9:15	393.60	979.20	1372.80
9:30	391.68	940.80	1332.48
9:45	389.76	950.40	1340.16
10:00	385.92	960.00	1345.92
10:15	391.68	969.60	1361.28
10:30	391.68	1046.40	1438.08
10:45	380.16	1670.40	2050.56
11:00	405.12	1776.00	2181.12
11:15	391.68	1852.80	2244.48
11:30	380.16	1852.80	2232.96
11:45	385.92	1833.60	2219.52
12:00	407.04	1420.80	1827.84
12:15	378.24	1756.80	2135.04
12:30	385.92	1833.60	2219.52
12:45	393.60	1862.40	2256.00
13:00	395.52	1872.00	2267.52
13:15	393.60	1852.80	2246.40
13:30	416.64	1814.40	2231.04
13:45	405.12	1766.40	2171.52
14:00	412.80	1670.40	2083.20
14:15	382.08	1651.20	2033.28
14:30	401.28	1641.60	2042.88
14:45	387.84	1670.40	2058.24
15:00	407.04	1718.40	2125.44
15:15	399.36	1699.20	2098.56
15:30	408.96	1680.00	2088.96
15:45	414.72	1756.80	2171.52
16:00	407.04	1756.80	2163.84
16:15	426.24	1593.60	2019.84
16:30	410.88	1344.00	1754.88
16:45	399.36	1910.40	2309.76
17:00	407.04	2035.20	2442.24
17:15	435.84	1948.80	2384.64
17:30	418.56	1900.80	2319.36
17:45	407.04	1622.40	2029.44
18:00	405.12	1584.00	1989.12
18:15	399.36	1680.00	2079.36
18:30	410.88	1286.40	1697.28
18:45	420.48	1584.00	2004.48
19:00	435.84	1996.80	2432.64
19:15	420.48	1948.80	2369.28
19:30	416.64	1996.80	2413.44
19:45	428.16	2006.40	2434.56
20:00	407.04	1920.00	2327.04
20:15	393.60	1948.80	2342.40
20:30	385.92	1910.40	2296.32
20:45	408.96	1920.00	2328.96
21:00	387.84	1852.80	2240.64
21:15	380.16	1718.40	2098.56
21:30	378.24	1718.40	2096.64
21:45	374.40	1804.80	2179.20
22:00	376.32	1795.20	2171.52
22:15	360.96	1804.80	2165.76

		Store A	Store B	Store A + Store B
	22:30	360.96	1737.60	2098.56
	22:45	349.44	1833.60	2183.04
	23:00	353.28	1766.40	2119.68
	23:15	359.04	1737.60	2096.64
	23:30	362.88	1651.20	2014.08
	23:45	353.28	1824.00	2177.28
1/8/2010	0:00	359.04	1708.80	2067.84
	0:15	334.08	1833.60	2167.68
	0:30	320.64	1708.80	2029.44
	0:45	312.96	1747.20	2060.16
	1:00	311.04	1632.00	1943.04
	1:15	311.04	1708.80	2019.84
	1:30	312.96	1804.80	2117.76
	1:45	314.88	1795.20	2110.08
	2:00	307.20	1872.00	2179.20
	2:15	336.00	1872.00	2208.00
	2:30	366.72	1920.00	2286.72
	2:45	366.72	1862.40	2229.12
	3:00	336.00	1881.60	2217.60
	3:15	336.00	1651.20	1987.20
	3:30	316.80	1776.00	2092.80
	3:45	309.12	1795.20	2104.32
	4:00	312.96	1900.80	2213.76
	4:15	322.56	1929.60	2252.16
	4:30	326.40	1843.20	2169.60
	4:45	307.20	1814.40	2121.60
	5:00	303.36	1641.60	1944.96
	5:15	307.20	1622.40	1929.60
	5:30	309.12	1670.40	1979.52
	5:45	316.80	1680.00	1996.80
	6:00	305.28	1737.60	2042.88
	6:15	336.00	1747.20	2083.20
	6:30	341.76	1680.00	2021.76
	6:45	336.00	1545.60	1881.60
	7:00	328.32	1843.20	2171.52
	7:15	395.52	1939.20	2334.72
	7:30	395.52	1881.60	2277.12
	7:45	403.20	1929.60	2332.80
	8:00	410.88	1891.20	2302.08
	8:15	384.00	1852.80	2236.80
	8:30	380.16	1881.60	2261.76
	8:45	380.16	1862.40	2242.56
	9:00	380.16	1929.60	2309.76
	9:15	376.32	1929.60	2305.92
	9:30	376.32	1785.60	2161.92
	9:45	389.76	1872.00	2261.76
	10:00	364.80	1881.60	2246.40
	10:15	389.76	1996.80	2386.56
	10:30	420.48	1987.20	2407.68
	10:45	384.00	2083.20	2467.20
	11:00	370.56	2064.00	2434.56
	11:15	370.56	2016.00	2386.56
	11:30	378.24	1939.20	2317.44
	11:45	366.72	1948.80	2315.52
	12:00	397.44	1958.40	2355.84
	12:15	364.80	2140.80	2505.60
	12:30	387.84	2064.00	2451.84
	12:45	374.40	2035.20	2409.60
	13:00	389.76	2044.80	2434.56
	13:15	382.08	2054.40	2436.48
	13:30	399.36	2073.60	2472.96
	13:45	395.52	2016.00	2411.52
	14:00	395.52	2083.20	2478.72
	14:15	362.88	2025.60	2388.48
	14:30	368.64	1987.20	2355.84
	14:45	382.08	2054.40	2436.48
	15:00	368.64	2054.40	2423.04
	15:15	370.56	2092.80	2463.36
	15:30	384.00	2006.40	2390.40
	15:45	385.92	2016.00	2401.92
	16:00	368.64	2112.00	2480.64
	16:15	362.88	2179.20	2542.08
	16:30	380.16	2169.60	2549.76
	16:45	395.52	2112.00	2507.52

		Store A	Store B	Store A + Store B
	17:00	376.32	2131.20	2507.52
	17:15	374.40	2016.00	2390.40
	17:30	372.48	1929.60	2302.08
	17:45	393.60	1852.80	2246.40
	18:00	401.28	1881.60	2282.88
	18:15	405.12	2083.20	2488.32
	18:30	403.20	1996.80	2400.00
	18:45	385.92	2044.80	2430.72
	19:00	395.52	1996.80	2392.32
	19:15	387.84	1977.60	2365.44
	19:30	391.68	2083.20	2474.88
	19:45	393.60	2092.80	2486.40
	20:00	384.00	1977.60	2361.60
	20:15	382.08	2044.80	2426.88
	20:30	395.52	2044.80	2440.32
	20:45	397.44	1958.40	2355.84
	21:00	389.76	2035.20	2424.96
	21:15	360.96	2054.40	2415.36
	21:30	360.96	2083.20	2444.16
	21:45	362.88	2092.80	2455.68
	22:00	360.96	2083.20	2444.16
	22:15	359.04	1958.40	2317.44
	22:30	360.96	1929.60	2290.56
	22:45	353.28	1900.80	2254.08
	23:00	343.68	1996.80	2340.48
	23:15	343.68	1996.80	2340.48
	23:30	347.52	1948.80	2296.32
	23:45	343.68	2035.20	2378.88
1/9/2010	0:00	353.28	1977.60	2330.88
	0:15	326.40	1977.60	2304.00
	0:30	324.48	1881.60	2206.08
	0:45	318.72	1968.00	2286.72
	1:00	312.96	1910.40	2223.36
	1:15	324.48	1968.00	2292.48
	1:30	316.80	2006.40	2323.20
	1:45	312.96	2044.80	2357.76
	2:00	307.20	2016.00	2323.20
	2:15	332.16	2083.20	2415.36
	2:30	337.92	2054.40	2392.32
	2:45	347.52	1929.60	2277.12
	3:00	328.32	2025.60	2353.92
	3:15	332.16	1948.80	2280.96
	3:30	339.84	2073.60	2413.44
	3:45	320.64	2092.80	2413.44
	4:00	320.64	2054.40	2375.04
	4:15	314.88	2102.40	2417.28
	4:30	318.72	2025.60	2344.32
	4:45	303.36	2035.20	2338.56
	5:00	299.52	1814.40	2113.92
	5:15	314.88	1891.20	2206.08
	5:30	314.88	1872.00	2186.88
	5:45	318.72	1910.40	2229.12
	6:00	312.96	1910.40	2223.36
	6:15	312.96	1977.60	2290.56
	6:30	326.40	1776.00	2102.40
	6:45	314.88	1900.80	2215.68
	7:00	349.44	1785.60	2135.04
	7:15	387.84	1881.60	2269.44
	7:30	397.44	1872.00	2269.44
	7:45	418.56	2083.20	2501.76
	8:00	416.64	2044.80	2461.44
	8:15	401.28	2035.20	2436.48
	8:30	393.60	2044.80	2438.40
	8:45	380.16	1958.40	2338.56
	9:00	378.24	1987.20	2365.44
	9:15	372.48	1843.20	2215.68
	9:30	370.56	1776.00	2146.56
	9:45	370.56	1910.40	2280.96
	10:00	380.16	1689.60	2069.76
	10:15	368.64	1449.60	1818.24
	10:30	382.08	1488.00	1870.08
	10:45	357.12	1574.40	1931.52
	11:00	372.48	1497.60	1870.08
	11:15	366.72	1641.60	2008.32

		Store A	Store B	Store A + Store B
	11:30	359.04	2112.00	2471.04
	11:45	366.72	2035.20	2401.92
	12:00	376.32	2025.60	2401.92
	12:15	355.20	1996.80	2352.00
	12:30	370.56	1900.80	2271.36
	12:45	393.60	1785.60	2179.20
	13:00	382.08	1785.60	2167.68
	13:15	384.00	1776.00	2160.00
	13:30	378.24	1737.60	2115.84
	13:45	399.36	1766.40	2165.76
	14:00	378.24	1814.40	2192.64
	14:15	376.32	1670.40	2046.72
	14:30	389.76	1670.40	2060.16
	14:45	370.56	1747.20	2117.76
	15:00	359.04	1708.80	2067.84
	15:15	368.64	1804.80	2173.44
	15:30	370.56	1891.20	2261.76
	15:45	360.96	1824.00	2184.96
	16:00	368.64	1747.20	2115.84
	16:15	387.84	1747.20	2135.04
	16:30	384.00	1881.60	2265.60
	16:45	372.48	1660.80	2033.28
	17:00	374.40	1680.00	2054.40
	17:15	366.72	1622.40	1989.12
	17:30	368.64	1584.00	1952.64
	17:45	395.52	1651.20	2046.72
	18:00	405.12	1574.40	1979.52
	18:15	391.68	1660.80	2052.48
	18:30	407.04	1612.80	2019.84
	18:45	403.20	1632.00	2035.20
	19:00	391.68	1660.80	2052.48
	19:15	397.44	1699.20	2096.64
	19:30	393.60	1804.80	2198.40
	19:45	403.20	1756.80	2160.00
	20:00	391.68	1776.00	2167.68
	20:15	374.40	1756.80	2131.20
	20:30	374.40	1814.40	2188.80
	20:45	385.92	1795.20	2181.12
	21:00	372.48	1804.80	2177.28
	21:15	357.12	1680.00	2037.12
	21:30	359.04	1689.60	2048.64
	21:45	357.12	1737.60	2094.72
	22:00	359.04	1708.80	2067.84
	22:15	353.28	1737.60	2090.88
	22:30	359.04	1776.00	2135.04
	22:45	337.92	1680.00	2017.92
	23:00	332.16	1795.20	2127.36
	23:15	334.08	1785.60	2119.68
	23:30	345.60	1728.00	2073.60
	23:45	345.60	1785.60	2131.20
1/10/2010	0:00	355.20	1708.80	2064.00
	0:15	324.48	1689.60	2014.08
	0:30	320.64	1708.80	2029.44
	0:45	307.20	1670.40	1977.60
	1:00	307.20	1747.20	2054.40
	1:15	311.04	1660.80	1971.84
	1:30	318.72	1680.00	1998.72
	1:45	309.12	1737.60	2046.72
	2:00	309.12	1699.20	2008.32
	2:15	322.56	1708.80	2031.36
	2:30	337.92	1776.00	2113.92
	2:45	334.08	1680.00	2014.08
	3:00	330.24	1699.20	2029.44
	3:15	336.00	1776.00	2112.00
	3:30	316.80	1708.80	2025.60
	3:45	312.96	1641.60	1954.56
	4:00	314.88	1612.80	1927.68
	4:15	316.80	1766.40	2083.20
	4:30	328.32	1660.80	1989.12
	4:45	309.12	1660.80	1969.92
	5:00	309.12	1670.40	1979.52
	5:15	307.20	1670.40	1977.60
	5:30	314.88	1680.00	1994.88
	5:45	314.88	1689.60	2004.48

		Store A	Store B	Store A + Store B
	6:00	322.56	1689.60	2012.16
	6:15	311.04	1737.60	2048.64
	6:30	318.72	1612.80	1931.52
	6:45	345.60	1622.40	1968.00
	7:00	357.12	1641.60	1998.72
	7:15	387.84	1632.00	2019.84
	7:30	410.88	1680.00	2090.88
	7:45	405.12	1680.00	2085.12
	8:00	416.64	1680.00	2096.64
	8:15	393.60	1756.80	2150.40
	8:30	389.76	1699.20	2088.96
	8:45	399.36	1670.40	2069.76
	9:00	399.36	1708.80	2108.16
	9:15	401.28	1708.80	2110.08
	9:30	422.40	1737.60	2160.00
	9:45	412.80	1737.60	2150.40
	10:00	401.28	1708.80	2110.08
	10:15	401.28	1718.40	2119.68
	10:30	410.88	1699.20	2110.08
	10:45	393.60	1680.00	2073.60
	11:00	380.16	1843.20	2223.36
	11:15	384.00	1776.00	2160.00
	11:30	378.24	1651.20	2029.44
	11:45	387.84	1852.80	2240.64
	12:00	389.76	1833.60	2223.36
	12:15	412.80	2006.40	2419.20
	12:30	393.60	2006.40	2400.00
	12:45	387.84	2035.20	2423.04
	13:00	385.92	1939.20	2325.12
	13:15	385.92	1987.20	2373.12
	13:30	414.72	1881.60	2296.32
	13:45	416.64	1824.00	2240.64
	14:00	395.52	1766.40	2161.92
	14:15	399.36	1862.40	2261.76
	14:30	401.28	1689.60	2090.88
	14:45	405.12	1708.80	2113.92
	15:00	387.84	1728.00	2115.84
	15:15	389.76	1958.40	2348.16
	15:30	389.76	1881.60	2271.36
	15:45	387.84	1872.00	2259.84
	16:00	424.32	1881.60	2305.92
	16:15	424.32	1862.40	2286.72
	16:30	432.00	1872.00	2304.00
	16:45	405.12	1785.60	2190.72
	17:00	410.88	1795.20	2206.08
	17:15	403.20	1632.00	2035.20
	17:30	408.96	1785.60	2194.56
	17:45	405.12	1766.40	2171.52
	18:00	403.20	1718.40	2121.60
	18:15	380.16	1852.80	2232.96
	18:30	384.00	1603.20	1987.20
	18:45	385.92	1507.20	1893.12
	19:00	374.40	1756.80	2131.20
	19:15	385.92	1756.80	2142.72
	19:30	389.76	1814.40	2204.16
	19:45	374.40	1795.20	2169.60
	20:00	366.72	1766.40	2133.12
	20:15	387.84	1689.60	2077.44
	20:30	397.44	1728.00	2125.44
	20:45	389.76	1843.20	2232.96
	21:00	389.76	1718.40	2108.16
	21:15	374.40	1718.40	2092.80
	21:30	364.80	1756.80	2121.60
	21:45	360.96	1699.20	2060.16
	22:00	368.64	1776.00	2144.64
	22:15	359.04	1641.60	2000.64
	22:30	364.80	1814.40	2179.20
	22:45	351.36	1718.40	2069.76
	23:00	345.60	1776.00	2121.60
	23:15	345.60	1804.80	2150.40
	23:30	351.36	1641.60	1992.96
	23:45	347.52	1766.40	2113.92
1/11/2010	0:00	343.68	1728.00	2071.68
	0:15	320.64	1766.40	2087.04

	Store A	Store B	Store A + Store B
0:30	330.24	1728.00	2058.24
0:45	312.96	1843.20	2156.16
1:00	311.04	1728.00	2039.04
1:15	311.04	1843.20	2154.24
1:30	322.56	1728.00	2050.56
1:45	312.96	1785.60	2098.56
2:00	318.72	1670.40	1989.12
2:15	332.16	1699.20	2031.36
2:30	332.16	1718.40	2050.56
2:45	336.00	1564.80	1900.80
3:00	330.24	1593.60	1923.84
3:15	336.00	1670.40	2006.40
3:30	332.16	1603.20	1935.36
3:45	312.96	1564.80	1877.76
4:00	318.72	1536.00	1854.72
4:15	320.64	1497.60	1818.24
4:30	336.00	1488.00	1824.00
4:45	312.96	1420.80	1733.76
5:00	307.20	1459.20	1766.40
5:15	312.96	1430.40	1743.36
5:30	322.56	1497.60	1820.16
5:45	312.96	1507.20	1820.16
6:00	312.96	1468.80	1781.76
6:15	318.72	1593.60	1912.32
6:30	332.16	1468.80	1800.96
6:45	337.92	1488.00	1825.92
7:00	326.40	1555.20	1881.60
7:15	389.76	1660.80	2050.56
7:30	408.96	1651.20	2060.16
7:45	401.28	1680.00	2081.28
8:00	387.84	1776.00	2163.84
8:15	385.92	1699.20	2085.12
8:30	389.76	1737.60	2127.36
8:45	407.04	1708.80	2115.84
9:00	403.20	1660.80	2064.00
9:15	389.76	1670.40	2060.16
9:30	401.28	1756.80	2158.08
9:45	405.12	1622.40	2027.52
10:00	399.36	1622.40	2021.76
10:15	397.44	1718.40	2115.84
10:30	389.76	1680.00	2069.76
10:45	374.40	1718.40	2092.80
11:00	360.96	1824.00	2184.96
11:15	360.96	1728.00	2088.96
11:30	380.16	1651.20	2031.36
11:45	364.80	1804.80	2169.60
12:00	372.48	1670.40	2042.88
12:15	372.48	1833.60	2206.08
12:30	374.40	1891.20	2265.60
12:45	372.48	1881.60	2254.08
13:00	370.56	1833.60	2204.16
13:15	374.40	1747.20	2121.60
13:30	399.36	1737.60	2136.96
13:45	389.76	1699.20	2088.96
14:00	387.84	1699.20	2087.04
14:15	391.68	1622.40	2014.08
14:30	395.52	1603.20	1998.72
14:45	399.36	1670.40	2069.76
15:00	410.88	1670.40	2081.28
15:15	376.32	1699.20	2075.52
15:30	384.00	1795.20	2179.20
15:45	385.92	1708.80	2094.72
16:00	391.68	1660.80	2052.48
16:15	364.80	1785.60	2150.40
16:30	366.72	1708.80	2075.52
16:45	353.28	1680.00	2033.28
17:00	372.48	1689.60	2062.08
17:15	382.08	1660.80	2042.88
17:30	370.56	1574.40	1944.96
17:45	393.60	1708.80	2102.40
18:00	414.72	1670.40	2085.12
18:15	410.88	1737.60	2148.48
18:30	395.52	1680.00	2075.52
18:45	391.68	1670.40	2062.08

		Store A	Store B	Store A + Store B
	19:00	397.44	1641.60	2039.04
	19:15	382.08	1728.00	2110.08
	19:30	391.68	1814.40	2206.08
	19:45	391.68	1833.60	2225.28
	20:00	391.68	1900.80	2292.48
	20:15	389.76	1795.20	2184.96
	20:30	403.20	1862.40	2265.60
	20:45	391.68	1776.00	2167.68
	21:00	380.16	1872.00	2252.16
	21:15	366.72	1785.60	2152.32
	21:30	370.56	1833.60	2204.16
	21:45	380.16	1804.80	2184.96
	22:00	360.96	1814.40	2175.36
	22:15	374.40	1747.20	2121.60
	22:30	378.24	1795.20	2173.44
	22:45	362.88	1699.20	2062.08
	23:00	357.12	1891.20	2248.32
	23:15	359.04	1833.60	2192.64
	23:30	359.04	1814.40	2173.44
	23:45	355.20	1891.20	2246.40
1/12/2010	0:00	360.96	1747.20	2108.16
	0:15	322.56	1737.60	2060.16
	0:30	336.00	1718.40	2054.40
	0:45	324.48	1728.00	2052.48
	1:00	328.32	1680.00	2008.32
	1:15	311.04	1689.60	2000.64
	1:30	328.32	1814.40	2142.72
	1:45	309.12	1756.80	2065.92
	2:00	316.80	1708.80	2025.60
	2:15	336.00	1766.40	2102.40
	2:30	332.16	1795.20	2127.36
	2:45	362.88	1699.20	2062.08
	3:00	332.16	1670.40	2002.56
	3:15	341.76	1689.60	2031.36
	3:30	326.40	1766.40	2092.80
	3:45	318.72	1641.60	1960.32
	4:00	318.72	1632.00	1950.72
	4:15	316.80	1641.60	1958.40
	4:30	326.40	1536.00	1862.40
	4:45	311.04	1555.20	1866.24
	5:00	303.36	1670.40	1973.76
	5:15	318.72	1593.60	1912.32
	5:30	320.64	1660.80	1981.44
	5:45	312.96	1699.20	2012.16
	6:00	311.04	1680.00	1991.04
	6:15	305.28	1651.20	1956.48
	6:30	364.80	1593.60	1958.40
	6:45	332.16	1612.80	1944.96
	7:00	324.48	1660.80	1985.28
	7:15	384.00	1612.80	1996.80
	7:30	393.60	1699.20	2092.80
	7:45	405.12	1747.20	2152.32
	8:00	399.36	1708.80	2108.16
	8:15	393.60	1785.60	2179.20
	8:30	397.44	1728.00	2125.44
	8:45	380.16	1651.20	2031.36
	9:00	370.56	1737.60	2108.16
	9:15	370.56	1689.60	2060.16
	9:30	385.92	1651.20	2037.12
	9:45	372.48	1612.80	1985.28
	10:00	376.32	1641.60	2017.92
	10:15	374.40	1593.60	1968.00
	10:30	382.08	1670.40	2052.48
	10:45	364.80	1785.60	2150.40
	11:00	362.88	1862.40	2225.28
	11:15	393.60	2006.40	2400.00
	11:30	380.16	1785.60	2165.76
	11:45	374.40	1977.60	2352.00
	12:00	385.92	1852.80	2238.72
	12:15	378.24	2073.60	2451.84
	12:30	387.84	1968.00	2355.84
	12:45	395.52	1968.00	2363.52
	13:00	385.92	1939.20	2325.12
	13:15	387.84	1920.00	2307.84

		Store A	Store B	Store A + Store B
	13:30	389.76	1785.60	2175.36
	13:45	380.16	1833.60	2213.76
	14:00	376.32	1804.80	2181.12
	14:15	378.24	1689.60	2067.84
	14:30	395.52	1670.40	2065.92
	14:45	387.84	1728.00	2115.84
	15:00	382.08	1756.80	2138.88
	15:15	366.72	1900.80	2267.52
	15:30	376.32	1872.00	2248.32
	15:45	376.32	1862.40	2238.72
	16:00	376.32	1862.40	2238.72
	16:15	359.04	1766.40	2125.44
	16:30	380.16	1795.20	2175.36
	16:45	366.72	1680.00	2046.72
	17:00	357.12	1670.40	2027.52
	17:15	355.20	1612.80	1968.00
	17:30	385.92	1603.20	1989.12
	17:45	399.36	1728.00	2127.36
	18:00	407.04	1622.40	2029.44
	18:15	407.04	1641.60	2048.64
	18:30	401.28	1545.60	1946.88
	18:45	399.36	1670.40	2069.76
	19:00	403.20	1680.00	2083.20
	19:15	389.76	1670.40	2060.16
	19:30	385.92	1747.20	2133.12
	19:45	395.52	1843.20	2238.72
	20:00	387.84	1670.40	2058.24
	20:15	384.00	1910.40	2294.40
	20:30	403.20	1872.00	2275.20
	20:45	378.24	1900.80	2279.04
	21:00	385.92	1814.40	2200.32
	21:15	368.64	1843.20	2211.84
	21:30	368.64	1747.20	2115.84
	21:45	366.72	1737.60	2104.32
	22:00	368.64	1708.80	2077.44
	22:15	359.04	1747.20	2106.24
	22:30	378.24	1766.40	2144.64
	22:45	355.20	1737.60	2092.80
	23:00	349.44	1862.40	2211.84
	23:15	351.36	1843.20	2194.56
	23:30	351.36	1660.80	2012.16
	23:45	351.36	1852.80	2204.16
1/13/2010	0:00	353.28	1843.20	2196.48
	0:15	332.16	1747.20	2079.36
	0:30	332.16	1833.60	2165.76
	0:45	318.72	1795.20	2113.92
	1:00	311.04	1737.60	2048.64
	1:15	320.64	1852.80	2173.44
	1:30	334.08	1747.20	2081.28
	1:45	305.28	1824.00	2129.28
	2:00	301.44	1737.60	2039.04
	2:15	320.64	1824.00	2144.64
	2:30	366.72	1804.80	2171.52
	2:45	347.52	1804.80	2152.32
	3:00	355.20	1737.60	2092.80
	3:15	353.28	1804.80	2158.08
	3:30	339.84	1747.20	2087.04
	3:45	322.56	1718.40	2040.96
	4:00	318.72	1776.00	2094.72
	4:15	318.72	1660.80	1979.52
	4:30	334.08	1766.40	2100.48
	4:45	312.96	1670.40	1983.36
	5:00	309.12	1660.80	1969.92
	5:15	311.04	1689.60	2000.64
	5:30	311.04	1708.80	2019.84
	5:45	301.44	1670.40	1971.84
	6:00	307.20	1593.60	1900.80
	6:15	309.12	1555.20	1864.32
	6:30	360.96	1516.80	1877.76
	6:45	330.24	1689.60	2019.84
	7:00	320.64	1660.80	1981.44
	7:15	378.24	1632.00	2010.24
	7:30	397.44	1785.60	2183.04
	7:45	384.00	1603.20	1987.20

		Store A	Store B	Store A + Store B
	8:00	387.84	1641.60	2029.44
	8:15	385.92	1660.80	2046.72
	8:30	393.60	1766.40	2160.00
	8:45	403.20	1958.40	2361.60
	9:00	401.28	1833.60	2234.88
	9:15	405.12	1939.20	2344.32
	9:30	384.00	1804.80	2188.80
	9:45	403.20	1910.40	2313.60
	10:00	401.28	1804.80	2206.08
	10:15	366.72	1872.00	2238.72
	10:30	362.88	1756.80	2119.68
	10:45	357.12	1881.60	2238.72
	11:00	359.04	1814.40	2173.44
	11:15	360.96	1920.00	2280.96
	11:30	362.88	1795.20	2158.08
	11:45	368.64	1824.00	2192.64
	12:00	374.40	1747.20	2121.60
	12:15	372.48	1929.60	2302.08
	12:30	385.92	1843.20	2229.12
	12:45	376.32	1948.80	2325.12
	13:00	370.56	1785.60	2156.16
	13:15	378.24	1593.60	1971.84
	13:30	372.48	1776.00	2148.48
	13:45	382.08	1910.40	2292.48
	14:00	385.92	1756.80	2142.72
	14:15	353.28	1708.80	2062.08
	14:30	374.40	1651.20	2025.60
	14:45	387.84	1728.00	2115.84
	15:00	372.48	1670.40	2042.88
	15:15	372.48	1852.80	2225.28
	15:30	385.92	1920.00	2305.92
	15:45	384.00	1872.00	2256.00
	16:00	374.40	1881.60	2256.00
	16:15	378.24	1833.60	2211.84
	16:30	374.40	1996.80	2371.20
	16:45	360.96	1824.00	2184.96
	17:00	374.40	1776.00	2150.40
	17:15	362.88	1766.40	2129.28
	17:30	408.96	1766.40	2175.36
	17:45	399.36	1900.80	2300.16
	18:00	410.88	1804.80	2215.68
	18:15	399.36	1900.80	2300.16
	18:30	401.28	1660.80	2062.08
	18:45	414.72	1622.40	2037.12
	19:00	395.52	1756.80	2152.32
	19:15	403.20	1977.60	2380.80
	19:30	416.64	1977.60	2394.24
	19:45	397.44	1996.80	2394.24
	20:00	401.28	1958.40	2359.68
	20:15	376.32	1910.40	2286.72
	20:30	387.84	1958.40	2346.24
	20:45	408.96	1891.20	2300.16
	21:00	384.00	1795.20	2179.20
	21:15	362.88	2016.00	2378.88
	21:30	362.88	1881.60	2244.48
	21:45	376.32	1843.20	2219.52
	22:00	368.64	1804.80	2173.44
	22:15	362.88	1862.40	2225.28
	22:30	366.72	1776.00	2142.72
	22:45	360.96	1747.20	2108.16
	23:00	353.28	1852.80	2206.08
	23:15	345.60	1824.00	2169.60
	23:30	357.12	1699.20	2056.32
	23:45	353.28	1747.20	2100.48
1/14/2010	0:00	359.04	1785.60	2144.64
	0:15	326.40	1785.60	2112.00
	0:30	322.56	1756.80	2079.36
	0:45	316.80	1776.00	2092.80
	1:00	316.80	1785.60	2102.40
	1:15	320.64	1795.20	2115.84
	1:30	322.56	1900.80	2223.36
	1:45	312.96	1728.00	2040.96
	2:00	312.96	1804.80	2117.76
	2:15	328.32	1756.80	2085.12

	Store A	Store B	Store A + Store B
2:30	337.92	1737.60	2075.52
2:45	339.84	1689.60	2029.44
3:00	332.16	1728.00	2060.16
3:15	343.68	1737.60	2081.28
3:30	339.84	1766.40	2106.24
3:45	322.56	1699.20	2021.76
4:00	312.96	1670.40	1983.36
4:15	314.88	1708.80	2023.68
4:30	332.16	1632.00	1964.16
4:45	301.44	1555.20	1856.64
5:00	303.36	1564.80	1868.16
5:15	314.88	1555.20	1870.08
5:30	311.04	1632.00	1943.04
5:45	307.20	1804.80	2112.00
6:00	309.12	1660.80	1969.92
6:15	322.56	1737.60	2060.16
6:30	351.36	1632.00	1983.36
6:45	334.08	1584.00	1918.08
7:00	328.32	1680.00	2008.32
7:15	364.80	1660.80	2025.60
7:30	399.36	1641.60	2040.96
7:45	389.76	1708.80	2098.56
8:00	395.52	1699.20	2094.72
8:15	393.60	1728.00	2121.60
8:30	401.28	1718.40	2119.68
8:45	399.36	1689.60	2088.96
9:00	374.40	1680.00	2054.40
9:15	368.64	1699.20	2067.84
9:30	374.40	1680.00	2054.40
9:45	372.48	1737.60	2110.08
10:00	389.76	1689.60	2079.36
10:15	380.16	1785.60	2165.76
10:30	391.68	1718.40	2110.08
10:45	378.24	1728.00	2106.24
11:00	384.00	1785.60	2169.60
11:15	366.72	1900.80	2267.52
11:30	384.00	1776.00	2160.00
11:45	391.68	1900.80	2292.48
12:00	376.32	1872.00	2248.32
12:15	376.32	2035.20	2411.52
12:30	378.24	1996.80	2375.04
12:45	376.32	1862.40	2238.72
13:00	401.28	1718.40	2119.68
13:15	376.32	1804.80	2181.12
13:30	397.44	1776.00	2173.44
13:45	399.36	1747.20	2146.56
14:00	395.52	1766.40	2161.92
14:15	389.76	1728.00	2117.76
14:30	395.52	1641.60	2037.12
14:45	382.08	1785.60	2167.68
15:00	368.64	1824.00	2192.64
15:15	376.32	1852.80	2229.12
15:30	408.96	1833.60	2242.56
15:45	378.24	1929.60	2307.84
16:00	380.16	1881.60	2261.76
16:15	382.08	1891.20	2273.28
16:30	410.88	1881.60	2292.48
16:45	378.24	1728.00	2106.24
17:00	389.76	1718.40	2108.16
17:15	424.32	1708.80	2133.12
17:30	410.88	1737.60	2148.48
17:45	418.56	1766.40	2184.96
18:00	420.48	1737.60	2158.08
18:15	393.60	1852.80	2246.40
18:30	408.96	1766.40	2175.36
18:45	391.68	1795.20	2186.88
19:00	401.28	1708.80	2110.08
19:15	387.84	1804.80	2192.64
19:30	401.28	1766.40	2167.68
19:45	382.08	1948.80	2330.88
20:00	384.00	1804.80	2188.80
20:15	368.64	1920.00	2288.64
20:30	378.24	1785.60	2163.84
20:45	382.08	1929.60	2311.68

		Store A	Store B	Store A + Store B
	21:00	391.68	1852.80	2244.48
	21:15	380.16	1910.40	2290.56
	21:30	378.24	1881.60	2259.84
	21:45	384.00	1900.80	2284.80
	22:00	380.16	1910.40	2290.56
	22:15	374.40	1756.80	2131.20
	22:30	384.00	1785.60	2169.60
	22:45	357.12	1728.00	2085.12
	23:00	353.28	1833.60	2186.88
	23:15	355.20	1852.80	2208.00
	23:30	359.04	1737.60	2096.64
	23:45	351.36	1881.60	2232.96
1/15/2010	0:00	355.20	1766.40	2121.60
	0:15	326.40	1728.00	2054.40
	0:30	328.32	1824.00	2152.32
	0:45	311.04	1728.00	2039.04
	1:00	312.96	1766.40	2079.36
	1:15	311.04	1814.40	2125.44
	1:30	314.88	1785.60	2100.48
	1:45	307.20	1795.20	2102.40
	2:00	309.12	1708.80	2017.92
	2:15	322.56	1785.60	2108.16
	2:30	324.48	1728.00	2052.48
	2:45	328.32	1689.60	2017.92
	3:00	326.40	1804.80	2131.20
	3:15	332.16	1756.80	2088.96
	3:30	324.48	1785.60	2110.08
	3:45	299.52	1833.60	2133.12
	4:00	295.68	1737.60	2033.28
	4:15	318.72	1747.20	2065.92
	4:30	316.80	1718.40	2035.20
	4:45	299.52	1660.80	1960.32
	5:00	299.52	1651.20	1950.72
	5:15	307.20	1603.20	1910.40
	5:30	309.12	1680.00	1989.12
	5:45	305.28	1718.40	2023.68
	6:00	332.16	1593.60	1925.76
	6:15	307.20	1680.00	1987.20
	6:30	378.24	1584.00	1962.24
	6:45	341.76	1603.20	1944.96
	7:00	324.48	1632.00	1956.48
	7:15	374.40	1689.60	2064.00
	7:30	374.40	1718.40	2092.80
	7:45	395.52	1737.60	2133.12
	8:00	401.28	1804.80	2206.08
	8:15	408.96	1795.20	2204.16
	8:30	393.60	1718.40	2112.00
	8:45	370.56	1737.60	2108.16
	9:00	380.16	1737.60	2117.76
	9:15	374.40	1737.60	2112.00
	9:30	384.00	1747.20	2131.20
	9:45	380.16	1852.80	2232.96
	10:00	378.24	1737.60	2115.84
	10:15	387.84	1776.00	2163.84
	10:30	393.60	1776.00	2169.60
	10:45	378.24	1795.20	2173.44
	11:00	370.56	1795.20	2165.76
	11:15	376.32	1430.40	1806.72
	11:30	372.48	1555.20	1927.68
	11:45	389.76	1843.20	2232.96
	12:00	399.36	1920.00	2319.36
	12:15	370.56	1958.40	2328.96
	12:30	389.76	1948.80	2338.56
	12:45	362.88	1929.60	2292.48
	13:00	366.72	1939.20	2305.92
	13:15	384.00	1939.20	2323.20
	13:30	389.76	1910.40	2300.16
	13:45	389.76	1968.00	2357.76
	14:00	362.88	1929.60	2292.48
	14:15	362.88	1766.40	2129.28
	14:30	368.64	1843.20	2211.84
	14:45	378.24	1728.00	2106.24
	15:00	410.88	1891.20	2302.08
	15:15	380.16	1958.40	2338.56

		Store A	Store B	Store A + Store B
	15:30	397.44	1824.00	2221.44
	15:45	407.04	1785.60	2192.64
	16:00	378.24	1929.60	2307.84
	16:15	376.32	1852.80	2229.12
	16:30	376.32	1852.80	2229.12
	16:45	370.56	1872.00	2242.56
	17:00	370.56	1804.80	2175.36
	17:15	368.64	1785.60	2154.24
	17:30	380.16	1804.80	2184.96
	17:45	372.48	1756.80	2129.28
	18:00	395.52	1776.00	2171.52
	18:15	403.20	1900.80	2304.00
	18:30	393.60	1776.00	2169.60
	18:45	412.80	1747.20	2160.00
	19:00	391.68	1747.20	2138.88
	19:15	405.12	1872.00	2277.12
	19:30	407.04	1824.00	2231.04
	19:45	403.20	1900.80	2304.00
	20:00	385.92	1776.00	2161.92
	20:15	372.48	1872.00	2244.48
	20:30	397.44	1785.60	2183.04
	20:45	391.68	1872.00	2263.68
	21:00	389.76	1785.60	2175.36
	21:15	385.92	1824.00	2209.92
	21:30	366.72	1852.80	2219.52
	21:45	370.56	1881.60	2252.16
	22:00	362.88	1948.80	2311.68
	22:15	359.04	1795.20	2154.24
	22:30	368.64	1833.60	2202.24
	22:45	341.76	1833.60	2175.36
	23:00	337.92	1833.60	2171.52
	23:15	337.92	1833.60	2171.52
	23:30	343.68	1680.00	2023.68
	23:45	343.68	1795.20	2138.88
1/16/2010	0:00	351.36	1689.60	2040.96
	0:15	322.56	1689.60	2012.16
	0:30	318.72	1747.20	2065.92
	0:45	322.56	1747.20	2069.76
	1:00	309.12	1708.80	2017.92
	1:15	314.88	1718.40	2033.28
	1:30	314.88	1795.20	2110.08
	1:45	305.28	1756.80	2062.08
	2:00	307.20	1737.60	2044.80
	2:15	314.88	1747.20	2062.08
	2:30	326.40	1785.60	2112.00
	2:45	326.40	1708.80	2035.20
	3:00	324.48	1737.60	2062.08
	3:15	332.16	1766.40	2098.56
	3:30	312.96	1756.80	2069.76
	3:45	324.48	1728.00	2052.48
	4:00	314.88	1699.20	2014.08
	4:15	316.80	1718.40	2035.20
	4:30	314.88	1670.40	1985.28
	4:45	293.76	1728.00	2021.76
	5:00	299.52	1680.00	1979.52
	5:15	297.60	1632.00	1929.60
	5:30	303.36	1785.60	2088.96
	5:45	297.60	1776.00	2073.60
	6:00	291.84	1708.80	2000.64
	6:15	295.68	1766.40	2062.08
	6:30	307.20	1737.60	2044.80
	6:45	305.28	1708.80	2014.08
	7:00	314.88	1699.20	2014.08
	7:15	357.12	1708.80	2065.92
	7:30	364.80	1747.20	2112.00
	7:45	385.92	1766.40	2152.32
	8:00	389.76	1718.40	2108.16
	8:15	376.32	1689.60	2065.92
	8:30	357.12	1670.40	2027.52
	8:45	376.32	1680.00	2056.32
	9:00	374.40	1756.80	2131.20
	9:15	376.32	1756.80	2133.12
	9:30	368.64	1785.60	2154.24
	9:45	368.64	1747.20	2115.84

		Store A	Store B	Store A + Store B
	10:00	364.80	1728.00	2092.80
	10:15	382.08	1776.00	2158.08
	10:30	370.56	1776.00	2146.56
	10:45	368.64	1766.40	2135.04
	11:00	382.08	1852.80	2234.88
	11:15	380.16	1478.40	1858.56
	11:30	360.96	1113.60	1474.56
	11:45	385.92	1094.40	1480.32
	12:00	366.72	1113.60	1480.32
	12:15	401.28	1152.00	1553.28
	12:30	389.76	1132.80	1522.56
	12:45	378.24	1123.20	1501.44
	13:00	389.76	1123.20	1512.96
	13:15	401.28	1094.40	1495.68
	13:30	384.00	1075.20	1459.20
	13:45	389.76	1113.60	1503.36
	14:00	385.92	1075.20	1461.12
	14:15	395.52	1036.80	1432.32
	14:30	387.84	1104.00	1491.84
	14:45	382.08	1795.20	2177.28
	15:00	368.64	2102.40	2471.04
	15:15	360.96	1843.20	2204.16
	15:30	376.32	1430.40	1806.72
	15:45	376.32	1353.60	1729.92
	16:00	387.84	1459.20	1847.04
	16:15	359.04	1948.80	2307.84
	16:30	399.36	2102.40	2501.76
	16:45	368.64	2160.00	2528.64
	17:00	382.08	1987.20	2369.28
	17:15	389.76	1843.20	2232.96
	17:30	376.32	1708.80	2085.12
	17:45	366.72	1776.00	2142.72
	18:00	407.04	1728.00	2135.04
	18:15	393.60	1852.80	2246.40
	18:30	403.20	1785.60	2188.80
	18:45	401.28	1689.60	2090.88
	19:00	380.16	1756.80	2136.96
	19:15	395.52	1852.80	2248.32
	19:30	395.52	1920.00	2315.52
	19:45	397.44	1987.20	2384.64
	20:00	389.76	1948.80	2338.56
	20:15	380.16	1900.80	2280.96
	20:30	385.92	1891.20	2277.12
	20:45	389.76	1881.60	2271.36
	21:00	359.04	1872.00	2231.04
	21:15	364.80	1900.80	2265.60
	21:30	374.40	1996.80	2371.20
	21:45	372.48	1958.40	2330.88
	22:00	359.04	1977.60	2336.64
	22:15	360.96	1939.20	2300.16
	22:30	364.80	2025.60	2390.40
	22:45	351.36	1958.40	2309.76
	23:00	343.68	2006.40	2350.08
	23:15	349.44	2016.00	2365.44
	23:30	349.44	2035.20	2384.64
	23:45	349.44	2073.60	2423.04
1/17/2010	0:00	355.20	2073.60	2428.80
	0:15	334.08	2083.20	2417.28
	0:30	326.40	2025.60	2352.00
	0:45	320.64	1996.80	2317.44
	1:00	303.36	1948.80	2252.16
	1:15	314.88	1958.40	2273.28
	1:30	314.88	2054.40	2369.28
	1:45	316.80	1929.60	2246.40
	2:00	320.64	1948.80	2269.44
	2:15	316.80	2016.00	2332.80
	2:30	328.32	1910.40	2238.72
	2:45	336.00	1987.20	2323.20
	3:00	332.16	1843.20	2175.36
	3:15	334.08	1833.60	2167.68
	3:30	326.40	1862.40	2188.80
	3:45	314.88	1766.40	2081.28
	4:00	316.80	1641.60	1958.40
	4:15	311.04	1632.00	1943.04

	Store A	Store B	Store A + Store B
4:30	328.32	1660.80	1989.12
4:45	307.20	1708.80	2016.00
5:00	299.52	1699.20	1998.72
5:15	303.36	1564.80	1868.16
5:30	314.88	1382.40	1697.28
5:45	309.12	1660.80	1969.92
6:00	312.96	1660.80	1973.76
6:15	309.12	1622.40	1931.52
6:30	320.64	1612.80	1933.44
6:45	318.72	1584.00	1902.72
7:00	326.40	1574.40	1900.80
7:15	382.08	1593.60	1975.68
7:30	387.84	1564.80	1952.64
7:45	407.04	1660.80	2067.84
8:00	399.36	1766.40	2165.76
8:15	378.24	1804.80	2183.04
8:30	395.52	1785.60	2181.12
8:45	393.60	1728.00	2121.60
9:00	378.24	1766.40	2144.64
9:15	380.16	1737.60	2117.76
9:30	374.40	1737.60	2112.00
9:45	395.52	1776.00	2171.52
10:00	387.84	1737.60	2125.44
10:15	374.40	1699.20	2073.60
10:30	380.16	1785.60	2165.76
10:45	368.64	1651.20	2019.84
11:00	376.32	1718.40	2094.72
11:15	366.72	1795.20	2161.92
11:30	368.64	1641.60	2010.24
11:45	360.96	1756.80	2117.76
12:00	382.08	1929.60	2311.68
12:15	393.60	1843.20	2236.80
12:30	397.44	1852.80	2250.24
12:45	378.24	1824.00	2202.24
13:00	403.20	1795.20	2198.40
13:15	399.36	1776.00	2175.36
13:30	391.68	1939.20	2330.88
13:45	389.76	1910.40	2300.16
14:00	389.76	1920.00	2309.76
14:15	374.40	1891.20	2265.60
14:30	399.36	1814.40	2213.76
14:45	405.12	1900.80	2305.92
15:00	387.84	1852.80	2240.64
15:15	389.76	1948.80	2338.56
15:30	376.32	1977.60	2353.92
15:45	382.08	1804.80	2186.88
16:00	389.76	1852.80	2242.56
16:15	395.52	1776.00	2171.52
16:30	412.80	1814.40	2227.20
16:45	387.84	1824.00	2211.84
17:00	376.32	1689.60	2065.92
17:15	385.92	1651.20	2037.12
17:30	389.76	1612.80	2002.56
17:45	420.48	1660.80	2081.28
18:00	412.80	1641.60	2054.40
18:15	414.72	1708.80	2123.52
18:30	405.12	1728.00	2133.12
18:45	397.44	1718.40	2115.84
19:00	393.60	1622.40	2016.00
19:15	397.44	1651.20	2048.64
19:30	422.40	1747.20	2169.60
19:45	408.96	1728.00	2136.96
20:00	385.92	1737.60	2123.52
20:15	380.16	1852.80	2232.96
20:30	395.52	1804.80	2200.32
20:45	393.60	1737.60	2131.20
21:00	385.92	1756.80	2142.72
21:15	366.72	1737.60	2104.32
21:30	370.56	1699.20	2069.76
21:45	376.32	1660.80	2037.12
22:00	362.88	1670.40	2033.28
22:15	370.56	1843.20	2213.76
22:30	374.40	1708.80	2083.20
22:45	355.20	1737.60	2092.80

		Store A	Store B	Store A + Store B
	23:00	343.68	1833.60	2177.28
	23:15	341.76	1795.20	2136.96
	23:30	353.28	1766.40	2119.68
	23:45	351.36	1900.80	2252.16
1/18/2010	0:00	347.52	1651.20	1998.72
	0:15	316.80	1593.60	1910.40
	0:30	320.64	1632.00	1952.64
	0:45	312.96	1641.60	1954.56
	1:00	301.44	1612.80	1914.24
	1:15	311.04	1651.20	1962.24
	1:30	318.72	1708.80	2027.52
	1:45	303.36	1632.00	1935.36
	2:00	307.20	1670.40	1977.60
	2:15	316.80	1689.60	2006.40
	2:30	324.48	1670.40	1994.88
	2:45	326.40	1651.20	1977.60
	3:00	324.48	1593.60	1918.08
	3:15	334.08	1622.40	1956.48
	3:30	324.48	1641.60	1966.08
	3:45	314.88	1545.60	1860.48
	4:00	318.72	1526.40	1845.12
	4:15	322.56	1526.40	1848.96
	4:30	326.40	1536.00	1862.40
	4:45	312.96	1526.40	1839.36
	5:00	303.36	1516.80	1820.16
	5:15	318.72	1564.80	1883.52
	5:30	334.08	1526.40	1860.48
	5:45	320.64	1564.80	1885.44
	6:00	318.72	1584.00	1902.72
	6:15	328.32	1632.00	1960.32
	6:30	347.52	1516.80	1864.32
	6:45	330.24	1526.40	1856.64
	7:00	337.92	1536.00	1873.92
	7:15	380.16	1564.80	1944.96
	7:30	416.64	1564.80	1981.44
	7:45	407.04	1603.20	2010.24
	8:00	385.92	1651.20	2037.12
	8:15	378.24	1689.60	2067.84
	8:30	387.84	1699.20	2087.04
	8:45	399.36	1766.40	2165.76
	9:00	393.60	1680.00	2073.60
	9:15	407.04	1699.20	2106.24
	9:30	395.52	1718.40	2113.92
	9:45	370.56	1641.60	2012.16
	10:00	359.04	1651.20	2010.24
	10:15	357.12	1660.80	2017.92
	10:30	347.52	1641.60	1989.12
	10:45	353.28	1651.20	2004.48
	11:00	345.60	1670.40	2016.00
	11:15	376.32	1612.80	1989.12
	11:30	349.44	1574.40	1923.84
	11:45	384.00	1756.80	2140.80
	12:00	359.04	1670.40	2029.44
	12:15	374.40	1776.00	2150.40
	12:30	364.80	1795.20	2160.00
	12:45	347.52	1718.40	2065.92
	13:00	376.32	1660.80	2037.12
	13:15	382.08	1612.80	1994.88
	13:30	385.92	1776.00	2161.92
	13:45	376.32	1718.40	2094.72
	14:00	399.36	1689.60	2088.96
	14:15	389.76	1680.00	2069.76
	14:30	382.08	1708.80	2090.88
	14:45	385.92	1718.40	2104.32
	15:00	380.16	1699.20	2079.36
	15:15	389.76	1708.80	2098.56
	15:30	376.32	1699.20	2075.52
	15:45	387.84	1680.00	2067.84
	16:00	387.84	1660.80	2048.64
	16:15	378.24	1651.20	2029.44
	16:30	382.08	1593.60	1975.68
	16:45	389.76	1545.60	1935.36
	17:00	389.76	1516.80	1906.56
	17:15	399.36	1488.00	1887.36

		Store A	Store B	Store A + Store B
	17:30	385.92	1536.00	1921.92
	17:45	391.68	1680.00	2071.68
	18:00	395.52	1584.00	1979.52
	18:15	382.08	1670.40	2052.48
	18:30	389.76	1708.80	2098.56
	18:45	391.68	1612.80	2004.48
	19:00	382.08	1584.00	1966.08
	19:15	389.76	1612.80	2002.56
	19:30	401.28	1632.00	2033.28
	19:45	397.44	1728.00	2125.44
	20:00	399.36	1651.20	2050.56
	20:15	391.68	1737.60	2129.28
	20:30	391.68	1718.40	2110.08
	20:45	393.60	1641.60	2035.20
	21:00	366.72	1747.20	2113.92
	21:15	359.04	1651.20	2010.24
	21:30	372.48	1680.00	2052.48
	21:45	370.56	1699.20	2069.76
	22:00	360.96	1689.60	2050.56
	22:15	364.80	1699.20	2064.00
	22:30	370.56	1680.00	2050.56
	22:45	351.36	1680.00	2031.36
	23:00	353.28	1699.20	2052.48
	23:15	355.20	1670.40	2025.60
	23:30	345.60	1660.80	2006.40
	23:45	343.68	1728.00	2071.68
1/19/2010	0:00	349.44	1651.20	2000.64
	0:15	320.64	1689.60	2010.24
	0:30	320.64	1689.60	2010.24
	0:45	316.80	1680.00	1996.80
	1:00	299.52	1670.40	1969.92
	1:15	309.12	1680.00	1989.12
	1:30	314.88	1814.40	2129.28
	1:45	297.60	1737.60	2035.20
	2:00	309.12	1737.60	2046.72
	2:15	320.64	1708.80	2029.44
	2:30	334.08	1814.40	2148.48
	2:45	349.44	1699.20	2048.64
	3:00	318.72	1737.60	2056.32
	3:15	330.24	1824.00	2154.24
	3:30	316.80	1718.40	2035.20
	3:45	303.36	1804.80	2108.16
	4:00	307.20	1708.80	2016.00
	4:15	314.88	1651.20	1966.08
	4:30	314.88	1632.00	1946.88
	4:45	307.20	1593.60	1900.80
	5:00	295.68	1555.20	1850.88
	5:15	314.88	1430.40	1745.28
	5:30	320.64	1516.80	1837.44
	5:45	316.80	1545.60	1862.40
	6:00	314.88	1392.00	1706.88
	6:15	314.88	1574.40	1889.28
	6:30	339.84	1612.80	1952.64
	6:45	316.80	1555.20	1872.00
	7:00	312.96	1641.60	1954.56
	7:15	385.92	1670.40	2056.32
	7:30	385.92	1718.40	2104.32
	7:45	384.00	1766.40	2150.40
	8:00	372.48	1756.80	2129.28
	8:15	351.36	1766.40	2117.76
	8:30	378.24	1766.40	2144.64
	8:45	378.24	1708.80	2087.04
	9:00	359.04	1795.20	2154.24
	9:15	360.96	1795.20	2156.16
	9:30	368.64	1747.20	2115.84
	9:45	391.68	1766.40	2158.08
	10:00	372.48	1795.20	2167.68
	10:15	364.80	1776.00	2140.80
	10:30	364.80	1814.40	2179.20
	10:45	384.00	1814.40	2198.40
	11:00	370.56	1766.40	2136.96
	11:15	364.80	1708.80	2073.60
	11:30	362.88	1670.40	2033.28
	11:45	362.88	1929.60	2292.48

		Store A	Store B	Store A + Store B
	12:00	362.88	1776.00	2138.88
	12:15	351.36	1843.20	2194.56
	12:30	353.28	1891.20	2244.48
	12:45	359.04	1824.00	2183.04
	13:00	366.72	1814.40	2181.12
	13:15	372.48	1872.00	2244.48
	13:30	360.96	1833.60	2194.56
	13:45	372.48	1804.80	2177.28
	14:00	374.40	1843.20	2217.60
	14:15	360.96	1689.60	2050.56
	14:30	366.72	1785.60	2152.32
	14:45	372.48	1776.00	2148.48
	15:00	366.72	1766.40	2133.12
	15:15	380.16	1891.20	2271.36
	15:30	372.48	1862.40	2234.88
	15:45	376.32	1737.60	2113.92
	16:00	366.72	1737.60	2104.32
	16:15	359.04	1891.20	2250.24
	16:30	360.96	1728.00	2088.96
	16:45	359.04	1718.40	2077.44
	17:00	351.36	1670.40	2021.76
	17:15	360.96	1612.80	1973.76
	17:30	366.72	1574.40	1941.12
	17:45	370.56	1689.60	2060.16
	18:00	385.92	1632.00	2017.92
	18:15	380.16	1728.00	2108.16
	18:30	397.44	1603.20	2000.64
	18:45	385.92	1526.40	1912.32
	19:00	374.40	1526.40	1900.80
	19:15	372.48	1660.80	2033.28
	19:30	385.92	1708.80	2094.72
	19:45	378.24	1756.80	2135.04
	20:00	374.40	1718.40	2092.80
	20:15	368.64	1728.00	2096.64
	20:30	378.24	1776.00	2154.24
	20:45	368.64	1728.00	2096.64
	21:00	366.72	1708.80	2075.52
	21:15	368.64	1641.60	2010.24
	21:30	366.72	1660.80	2027.52
	21:45	366.72	1776.00	2142.72
	22:00	360.96	1699.20	2060.16
	22:15	357.12	1670.40	2027.52
	22:30	360.96	1737.60	2098.56
	22:45	343.68	1651.20	1994.88
	23:00	336.00	1756.80	2092.80
	23:15	345.60	1795.20	2140.80
	23:30	347.52	1689.60	2037.12
	23:45	345.60	1795.20	2140.80
1/20/2010	0:00	351.36	1737.60	2088.96
	0:15	326.40	1689.60	2016.00
	0:30	314.88	1718.40	2033.28
	0:45	314.88	1737.60	2052.48
	1:00	303.36	1699.20	2002.56
	1:15	301.44	1718.40	2019.84
	1:30	309.12	1785.60	2094.72
	1:45	305.28	1708.80	2014.08
	2:00	307.20	1766.40	2073.60
	2:15	309.12	1766.40	2075.52
	2:30	314.88	1862.40	2177.28
	2:45	320.64	1737.60	2058.24
	3:00	320.64	1747.20	2067.84
	3:15	324.48	1756.80	2081.28
	3:30	314.88	1670.40	1985.28
	3:45	305.28	1660.80	1966.08
	4:00	291.84	1622.40	1914.24
	4:15	314.88	1622.40	1937.28
	4:30	309.12	1651.20	1960.32
	4:45	288.00	1593.60	1881.60
	5:00	291.84	1536.00	1827.84
	5:15	295.68	1564.80	1860.48
	5:30	297.60	1555.20	1852.80
	5:45	289.92	1670.40	1960.32
	6:00	297.60	1603.20	1900.80
	6:15	311.04	1680.00	1991.04

		Store A	Store B	Store A + Store B
	6:30	341.76	1574.40	1916.16
	6:45	305.28	1612.80	1918.08
	7:00	297.60	1641.60	1939.20
	7:15	357.12	1660.80	2017.92
	7:30	374.40	1680.00	2054.40
	7:45	380.16	1718.40	2098.56
	8:00	374.40	1756.80	2131.20
	8:15	366.72	1747.20	2113.92
	8:30	366.72	1718.40	2085.12
	8:45	382.08	1718.40	2100.48
	9:00	368.64	1766.40	2135.04
	9:15	370.56	1766.40	2136.96
	9:30	370.56	1718.40	2088.96
	9:45	353.28	1718.40	2071.68
	10:00	359.04	1756.80	2115.84
	10:15	355.20	1785.60	2140.80
	10:30	364.80	1795.20	2160.00
	10:45	339.84	1776.00	2115.84
	11:00	341.76	1728.00	2069.76
	11:15	360.96	1747.20	2108.16
	11:30	366.72	1708.80	2075.52
	11:45	347.52	1900.80	2248.32
	12:00	364.80	1872.00	2236.80
	12:15	351.36	1900.80	2252.16
	12:30	370.56	2025.60	2396.16
	12:45	364.80	1843.20	2208.00
	13:00	366.72	1852.80	2219.52
	13:15	370.56	1872.00	2242.56
	13:30	382.08	1939.20	2321.28
	13:45	382.08	1881.60	2263.68
	14:00	378.24	1852.80	2231.04
	14:15	360.96	1920.00	2280.96
	14:30	364.80	1891.20	2256.00
	14:45	376.32	1996.80	2373.12
	15:00	366.72	1920.00	2286.72
	15:15	366.72	2035.20	2401.92
	15:30	374.40	2016.00	2390.40
	15:45	366.72	1910.40	2277.12
	16:00	360.96	1795.20	2156.16
	16:15	359.04	1766.40	2125.44
	16:30	366.72	1756.80	2123.52
	16:45	359.04	1651.20	2010.24
	17:00	355.20	1593.60	1948.80
	17:15	353.28	1593.60	1946.88
	17:30	368.64	1699.20	2067.84
	17:45	364.80	1593.60	1958.40
	18:00	389.76	1507.20	1896.96
	18:15	382.08	1699.20	2081.28
	18:30	387.84	1680.00	2067.84
	18:45	384.00	1612.80	1996.80
	19:00	374.40	1612.80	1987.20
	19:15	372.48	1651.20	2023.68
	19:30	384.00	1737.60	2121.60
	19:45	387.84	1862.40	2250.24
	20:00	366.72	1766.40	2133.12
	20:15	368.64	1718.40	2087.04
	20:30	380.16	1766.40	2146.56
	20:45	376.32	1737.60	2113.92
	21:00	372.48	1689.60	2062.08
	21:15	355.20	1689.60	2044.80
	21:30	368.64	1708.80	2077.44
	21:45	357.12	1776.00	2133.12
	22:00	351.36	1756.80	2108.16
	22:15	347.52	1718.40	2065.92
	22:30	359.04	1718.40	2077.44
	22:45	347.52	1766.40	2113.92
	23:00	345.60	1766.40	2112.00
	23:15	347.52	1718.40	2065.92
	23:30	341.76	1708.80	2050.56
	23:45	343.68	1737.60	2081.28
1/21/2010	0:00	345.60	1776.00	2121.60
	0:15	328.32	1699.20	2027.52
	0:30	314.88	1718.40	2033.28
	0:45	307.20	1747.20	2054.40

	Store A	Store B	Store A + Store B
1:00	293.76	1708.80	2002.56
1:15	301.44	1699.20	2000.64
1:30	303.36	1833.60	2136.96
1:45	295.68	1699.20	1994.88
2:00	305.28	1756.80	2062.08
2:15	322.56	1756.80	2079.36
2:30	318.72	1804.80	2123.52
2:45	334.08	1756.80	2090.88
3:00	322.56	1785.60	2108.16
3:15	324.48	1804.80	2129.28
3:30	311.04	1833.60	2144.64
3:45	309.12	1814.40	2123.52
4:00	293.76	1795.20	2088.96
4:15	305.28	1776.00	2081.28
4:30	309.12	1699.20	2008.32
4:45	291.84	1670.40	1962.24
5:00	291.84	1641.60	1933.44
5:15	288.00	1622.40	1910.40
5:30	293.76	1699.20	1992.96
5:45	295.68	1699.20	1994.88
6:00	289.92	1593.60	1883.52
6:15	299.52	1622.40	1921.92
6:30	320.64	1622.40	1943.04
6:45	305.28	1622.40	1927.68
7:00	307.20	1651.20	1958.40
7:15	343.68	1680.00	2023.68
7:30	357.12	1680.00	2037.12
7:45	368.64	1747.20	2115.84
8:00	370.56	1708.80	2079.36
8:15	345.60	1670.40	2016.00
8:30	349.44	1622.40	1971.84
8:45	359.04	1670.40	2029.44
9:00	345.60	1680.00	2025.60
9:15	351.36	1699.20	2050.56
9:30	351.36	1708.80	2060.16
9:45	355.20	1670.40	2025.60
10:00	370.56	1670.40	2040.96
10:15	360.96	1699.20	2060.16
10:30	384.00	1737.60	2121.60
10:45	351.36	1699.20	2050.56
11:00	347.52	1728.00	2075.52
11:15	349.44	1699.20	2048.64
11:30	360.96	1593.60	1954.56
11:45	368.64	1699.20	2067.84
12:00	370.56	1718.40	2088.96
12:15	368.64	1776.00	2144.64
12:30	370.56	1833.60	2204.16
12:45	378.24	1785.60	2163.84
13:00	360.96	1766.40	2127.36
13:15	355.20	1766.40	2121.60
13:30	372.48	1718.40	2090.88
13:45	387.84	1430.40	1818.24
14:00	376.32	1699.20	2075.52
14:15	366.72	1689.60	2056.32
14:30	372.48	1814.40	2186.88
14:45	391.68	1689.60	2081.28
15:00	374.40	1833.60	2208.00
15:15	389.76	1968.00	2357.76
15:30	376.32	1910.40	2286.72
15:45	368.64	1910.40	2279.04
16:00	372.48	1718.40	2090.88
16:15	357.12	1545.60	1902.72
16:30	366.72	1497.60	1864.32
16:45	360.96	1142.40	1503.36
17:00	370.56	1536.00	1906.56
17:15	370.56	1843.20	2213.76
17:30	384.00	1776.00	2160.00
17:45	362.88	1660.80	2023.68
18:00	374.40	1593.60	1968.00
18:15	391.68	1795.20	2186.88
18:30	387.84	1699.20	2087.04
18:45	395.52	1670.40	2065.92
19:00	382.08	1641.60	2023.68
19:15	391.68	1708.80	2100.48

		Store A	Store B	Store A + Store B
	19:30	374.40	1776.00	2150.40
	19:45	374.40	1804.80	2179.20
	20:00	364.80	1766.40	2131.20
	20:15	364.80	1766.40	2131.20
	20:30	374.40	1689.60	2064.00
	20:45	376.32	1689.60	2065.92
	21:00	372.48	1680.00	2052.48
	21:15	364.80	1699.20	2064.00
	21:30	359.04	1804.80	2163.84
	21:45	357.12	1804.80	2161.92
	22:00	343.68	1824.00	2167.68
	22:15	347.52	1785.60	2133.12
	22:30	353.28	1728.00	2081.28
	22:45	339.84	1708.80	2048.64
	23:00	341.76	1747.20	2088.96
	23:15	345.60	1862.40	2208.00
	23:30	341.76	1776.00	2117.76
	23:45	343.68	1968.00	2311.68
1/22/2010	0:00	349.44	1843.20	2192.64
	0:15	318.72	1862.40	2181.12
	0:30	309.12	1843.20	2152.32
	0:45	303.36	1833.60	2136.96
	1:00	288.00	1852.80	2140.80
	1:15	311.04	1776.00	2087.04
	1:30	309.12	1891.20	2200.32
	1:45	301.44	1708.80	2010.24
	2:00	301.44	1776.00	2077.44
	2:15	324.48	1804.80	2129.28
	2:30	324.48	1872.00	2196.48
	2:45	322.56	1814.40	2136.96
	3:00	316.80	1824.00	2140.80
	3:15	332.16	1852.80	2184.96
	3:30	316.80	1747.20	2064.00
	3:45	314.88	1670.40	1985.28
	4:00	314.88	1651.20	1966.08
	4:15	318.72	1632.00	1950.72
	4:30	320.64	1603.20	1923.84
	4:45	309.12	1689.60	1998.72
	5:00	299.52	1708.80	2008.32
	5:15	316.80	1689.60	2006.40
	5:30	311.04	1660.80	1971.84
	5:45	307.20	1756.80	2064.00
	6:00	314.88	1718.40	2033.28
	6:15	318.72	1670.40	1989.12
	6:30	349.44	1632.00	1981.44
	6:45	332.16	1708.80	2040.96
	7:00	339.84	1776.00	2115.84
	7:15	372.48	1795.20	2167.68
	7:30	403.20	1785.60	2188.80
	7:45	393.60	1372.80	1766.40
	8:00	389.76	1766.40	2156.16
	8:15	389.76	1756.80	2146.56
	8:30	368.64	1824.00	2192.64
	8:45	378.24	1737.60	2115.84
	9:00	410.88	1804.80	2215.68
	9:15	374.40	1708.80	2083.20
	9:30	360.96	1766.40	2127.36
	9:45	376.32	1708.80	2085.12
	10:00	360.96	1776.00	2136.96
	10:15	357.12	1718.40	2075.52
	10:30	357.12	1728.00	2085.12
	10:45	351.36	1833.60	2184.96
	11:00	374.40	1708.80	2083.20
	11:15	372.48	1641.60	2014.08
	11:30	351.36	1814.40	2165.76
	11:45	372.48	1708.80	2081.28
	12:00	357.12	1756.80	2113.92
	12:15	366.72	1843.20	2209.92
	12:30	357.12	1708.80	2065.92
	12:45	351.36	1747.20	2098.56
	13:00	359.04	1756.80	2115.84
	13:15	370.56	1718.40	2088.96
	13:30	374.40	1814.40	2188.80
	13:45	393.60	1747.20	2140.80

		Store A	Store B	Store A + Store B
	14:00	368.64	1824.00	2192.64
	14:15	360.96	1824.00	2184.96
	14:30	382.08	1795.20	2177.28
	14:45	368.64	1737.60	2106.24
	15:00	368.64	1737.60	2106.24
	15:15	360.96	1747.20	2108.16
	15:30	360.96	1680.00	2040.96
	15:45	362.88	1795.20	2158.08
	16:00	362.88	1651.20	2014.08
	16:15	366.72	1632.00	1998.72
	16:30	370.56	1574.40	1944.96
	16:45	359.04	1632.00	1991.04
	17:00	355.20	1545.60	1900.80
	17:15	362.88	1680.00	2042.88
	17:30	364.80	1632.00	1996.80
	17:45	380.16	1680.00	2060.16
	18:00	372.48	1785.60	2158.08
	18:15	384.00	1363.20	1747.20
	18:30	395.52	1238.40	1633.92
	18:45	414.72	1728.00	2142.72
	19:00	389.76	1593.60	1983.36
	19:15	385.92	1795.20	2181.12
	19:30	403.20	1747.20	2150.40
	19:45	393.60	1814.40	2208.00
	20:00	380.16	1843.20	2223.36
	20:15	391.68	1766.40	2158.08
	20:30	391.68	1833.60	2225.28
	20:45	393.60	1718.40	2112.00
	21:00	372.48	1814.40	2186.88
	21:15	366.72	1776.00	2142.72
	21:30	372.48	1852.80	2225.28
	21:45	364.80	1833.60	2198.40
	22:00	360.96	1814.40	2175.36
	22:15	357.12	1795.20	2152.32
	22:30	368.64	1824.00	2192.64
	22:45	345.60	1929.60	2275.20
	23:00	337.92	1872.00	2209.92
	23:15	353.28	1737.60	2090.88
	23:30	347.52	1872.00	2219.52
	23:45	351.36	1670.40	2021.76
1/23/2010	0:00	353.28	1843.20	2196.48
	0:15	326.40	1737.60	2064.00
	0:30	322.56	1766.40	2088.96
	0:45	307.20	1756.80	2064.00
	1:00	314.88	1785.60	2100.48
	1:15	312.96	1708.80	2021.76
	1:30	320.64	1584.00	1904.64
	1:45	311.04	1641.60	1952.64
	2:00	305.28	1651.20	1956.48
	2:15	328.32	1670.40	1998.72
	2:30	332.16	1670.40	2002.56
	2:45	336.00	1728.00	2064.00
	3:00	324.48	1747.20	2071.68
	3:15	339.84	1824.00	2163.84
	3:30	318.72	1670.40	1989.12
	3:45	312.96	1670.40	1983.36
	4:00	318.72	1804.80	2123.52
	4:15	314.88	1344.00	1658.88
	4:30	316.80	1305.60	1622.40
	4:45	303.36	1507.20	1810.56
	5:00	297.60	1632.00	1929.60
	5:15	316.80	1622.40	1939.20
	5:30	307.20	1747.20	2054.40
	5:45	314.88	1670.40	1985.28
	6:00	318.72	1785.60	2104.32
	6:15	311.04	1670.40	1981.44
	6:30	320.64	1708.80	2029.44
	6:45	312.96	1708.80	2021.76
	7:00	320.64	1756.80	2077.44
	7:15	378.24	1776.00	2154.24
	7:30	399.36	1833.60	2232.96
	7:45	424.32	1929.60	2353.92
	8:00	393.60	1708.80	2102.40
	8:15	405.12	1718.40	2123.52

		Store A	Store B	Store A + Store B
	8:30	384.00	1708.80	2092.80
	8:45	384.00	1670.40	2054.40
	9:00	376.32	1708.80	2085.12
	9:15	384.00	1699.20	2083.20
	9:30	391.68	1680.00	2071.68
	9:45	389.76	1785.60	2175.36
	10:00	370.56	1872.00	2242.56
	10:15	374.40	1910.40	2284.80
	10:30	393.60	1862.40	2256.00
	10:45	384.00	1910.40	2294.40
	11:00	372.48	1766.40	2138.88
	11:15	366.72	1632.00	1998.72
	11:30	378.24	1852.80	2231.04
	11:45	378.24	1872.00	2250.24
	12:00	364.80	1929.60	2294.40
	12:15	378.24	1977.60	2355.84
	12:30	366.72	1929.60	2296.32
	12:45	393.60	1939.20	2332.80
	13:00	401.28	1958.40	2359.68
	13:15	395.52	1920.00	2315.52
	13:30	395.52	1987.20	2382.72
	13:45	380.16	1910.40	2290.56
	14:00	372.48	1881.60	2254.08
	14:15	366.72	1948.80	2315.52
	14:30	385.92	1929.60	2315.52
	14:45	385.92	1852.80	2238.72
	15:00	380.16	1862.40	2242.56
	15:15	378.24	1881.60	2259.84
	15:30	384.00	1785.60	2169.60
	15:45	370.56	1891.20	2261.76
	16:00	385.92	1728.00	2113.92
	16:15	401.28	1785.60	2186.88
	16:30	391.68	1708.80	2100.48
	16:45	376.32	1555.20	1931.52
	17:00	378.24	1564.80	1943.04
	17:15	385.92	1555.20	1941.12
	17:30	380.16	1564.80	1944.96
	17:45	364.80	1612.80	1977.60
	18:00	401.28	1728.00	2129.28
	18:15	389.76	1574.40	1964.16
	18:30	391.68	1516.80	1908.48
	18:45	405.12	1670.40	2075.52
	19:00	391.68	1708.80	2100.48
	19:15	397.44	1737.60	2135.04
	19:30	395.52	1977.60	2373.12
	19:45	403.20	1872.00	2275.20
	20:00	387.84	1804.80	2192.64
	20:15	382.08	1910.40	2292.48
	20:30	382.08	1785.60	2167.68
	20:45	399.36	1766.40	2165.76
	21:00	374.40	1852.80	2227.20
	21:15	372.48	1776.00	2148.48
	21:30	370.56	1852.80	2223.36
	21:45	370.56	1910.40	2280.96
	22:00	362.88	1766.40	2129.28
	22:15	372.48	1795.20	2167.68
	22:30	359.04	1881.60	2240.64
	22:45	347.52	1872.00	2219.52
	23:00	345.60	1948.80	2294.40
	23:15	345.60	1833.60	2179.20
	23:30	339.84	1948.80	2288.64
	23:45	347.52	1891.20	2238.72
1/24/2010	0:00	353.28	1872.00	2225.28
	0:15	324.48	1910.40	2234.88
	0:30	326.40	1910.40	2236.80
	0:45	316.80	1824.00	2140.80
	1:00	305.28	1872.00	2177.28
	1:15	316.80	1814.40	2131.20
	1:30	324.48	1804.80	2129.28
	1:45	307.20	1795.20	2102.40
	2:00	312.96	1843.20	2156.16
	2:15	330.24	1968.00	2298.24
	2:30	332.16	1900.80	2232.96
	2:45	345.60	1824.00	2169.60

	Store A	Store B	Store A + Store B
3:00	326.40	1910.40	2236.80
3:15	332.16	1804.80	2136.96
3:30	324.48	1795.20	2119.68
3:45	311.04	1776.00	2087.04
4:00	312.96	1756.80	2069.76
4:15	316.80	1708.80	2025.60
4:30	320.64	1641.60	1962.24
4:45	303.36	1545.60	1848.96
5:00	297.60	1564.80	1862.40
5:15	307.20	1603.20	1910.40
5:30	307.20	1555.20	1862.40
5:45	295.68	1564.80	1860.48
6:00	305.28	1728.00	2033.28
6:15	320.64	1699.20	2019.84
6:30	328.32	1612.80	1941.12
6:45	324.48	1670.40	1994.88
7:00	320.64	1699.20	2019.84
7:15	368.64	1728.00	2096.64
7:30	376.32	1776.00	2152.32
7:45	382.08	1862.40	2244.48
8:00	403.20	1728.00	2131.20
8:15	391.68	1766.40	2158.08
8:30	385.92	1766.40	2152.32
8:45	408.96	1737.60	2146.56
9:00	378.24	1785.60	2163.84
9:15	351.36	1737.60	2088.96
9:30	378.24	1728.00	2106.24
9:45	378.24	1872.00	2250.24
10:00	364.80	1785.60	2150.40
10:15	362.88	1795.20	2158.08
10:30	380.16	1804.80	2184.96
10:45	360.96	1804.80	2165.76
11:00	351.36	1756.80	2108.16
11:15	364.80	1689.60	2054.40
11:30	366.72	1891.20	2257.92
11:45	368.64	1795.20	2163.84
12:00	370.56	1852.80	2223.36
12:15	376.32	1968.00	2344.32
12:30	391.68	1824.00	2215.68
12:45	385.92	1824.00	2209.92
13:00	385.92	1824.00	2209.92
13:15	372.48	1862.40	2234.88
13:30	384.00	1824.00	2208.00
13:45	364.80	1843.20	2208.00
14:00	353.28	1833.60	2186.88
14:15	330.24	1795.20	2125.44
14:30	345.60	1958.40	2304.00
14:45	362.88	1900.80	2263.68
15:00	387.84	1939.20	2327.04
15:15	389.76	2035.20	2424.96
15:30	380.16	1891.20	2271.36
15:45	359.04	1804.80	2163.84
16:00	355.20	1824.00	2179.20
16:15	357.12	1833.60	2190.72
16:30	366.72	1689.60	2056.32
16:45	362.88	1708.80	2071.68
17:00	359.04	1555.20	1914.24
17:15	382.08	1756.80	2138.88
17:30	359.04	1728.00	2087.04
17:45	357.12	1545.60	1902.72
18:00	368.64	1612.80	1981.44
18:15	384.00	1680.00	2064.00
18:30	389.76	1651.20	2040.96
18:45	378.24	1603.20	1981.44
19:00	372.48	1632.00	2004.48
19:15	374.40	1670.40	2044.80
19:30	378.24	1689.60	2067.84
19:45	376.32	1728.00	2104.32
20:00	362.88	1728.00	2090.88
20:15	351.36	1699.20	2050.56
20:30	362.88	1766.40	2129.28
20:45	366.72	1785.60	2152.32
21:00	366.72	1737.60	2104.32
21:15	360.96	1737.60	2098.56

		Store A	Store B	Store A + Store B
	21:30	353.28	1737.60	2090.88
	21:45	359.04	1766.40	2125.44
	22:00	347.52	1824.00	2171.52
	22:15	343.68	1756.80	2100.48
	22:30	357.12	1718.40	2075.52
	22:45	339.84	1766.40	2106.24
	23:00	330.24	1872.00	2202.24
	23:15	336.00	1660.80	1996.80
	23:30	334.08	1785.60	2119.68
	23:45	337.92	1824.00	2161.92
1/25/2010	0:00	339.84	1728.00	2067.84
	0:15	324.48	1737.60	2062.08
	0:30	309.12	1766.40	2075.52
	0:45	312.96	1718.40	2031.36
	1:00	297.60	1728.00	2025.60
	1:15	307.20	1660.80	1968.00
	1:30	307.20	1603.20	1910.40
	1:45	301.44	1632.00	1933.44
	2:00	305.28	1574.40	1879.68
	2:15	314.88	1555.20	1870.08
	2:30	316.80	1526.40	1843.20
	2:45	332.16	1574.40	1906.56
	3:00	318.72	1545.60	1864.32
	3:15	324.48	1488.00	1812.48
	3:30	318.72	1488.00	1806.72
	3:45	314.88	1478.40	1793.28
	4:00	324.48	1459.20	1783.68
	4:15	314.88	1459.20	1774.08
	4:30	339.84	1440.00	1779.84
	4:45	316.80	1401.60	1718.40
	5:00	303.36	1420.80	1724.16
	5:15	311.04	1526.40	1837.44
	5:30	314.88	1593.60	1908.48
	5:45	311.04	1507.20	1818.24
	6:00	318.72	1574.40	1893.12
	6:15	311.04	1564.80	1875.84
	6:30	311.04	1536.00	1847.04
	6:45	322.56	1564.80	1887.36
	7:00	332.16	1584.00	1916.16
	7:15	370.56	1593.60	1964.16
	7:30	372.48	1651.20	2023.68
	7:45	384.00	1612.80	1996.80
	8:00	366.72	1612.80	1979.52
	8:15	370.56	1584.00	1954.56
	8:30	357.12	1593.60	1950.72
	8:45	366.72	1651.20	2017.92
	9:00	360.96	1699.20	2060.16
	9:15	364.80	1641.60	2006.40
	9:30	355.20	1670.40	2025.60
	9:45	360.96	1689.60	2050.56
	10:00	343.68	1689.60	2033.28
	10:15	359.04	1718.40	2077.44
	10:30	357.12	1660.80	2017.92
	10:45	341.76	1708.80	2050.56
	11:00	370.56	1728.00	2098.56
	11:15	351.36	1632.00	1983.36
	11:30	349.44	1776.00	2125.44
	11:45	353.28	1785.60	2138.88
	12:00	360.96	1728.00	2088.96
	12:15	364.80	1747.20	2112.00
	12:30	364.80	1766.40	2131.20
	12:45	366.72	1776.00	2142.72
	13:00	359.04	1785.60	2144.64
	13:15	353.28	1708.80	2062.08
	13:30	384.00	1795.20	2179.20
	13:45	380.16	1804.80	2184.96
	14:00	380.16	1584.00	1964.16
	14:15	366.72	1574.40	1941.12
	14:30	366.72	1680.00	2046.72
	14:45	368.64	1756.80	2125.44
	15:00	359.04	1776.00	2135.04
	15:15	359.04	1756.80	2115.84
	15:30	368.64	1728.00	2096.64
	15:45	384.00	1660.80	2044.80

		Store A	Store B	Store A + Store B
	16:00	372.48	1584.00	1956.48
	16:15	376.32	1564.80	1941.12
	16:30	384.00	1478.40	1862.40
	16:45	376.32	1545.60	1921.92
	17:00	357.12	1516.80	1873.92
	17:15	357.12	1574.40	1931.52
	17:30	384.00	1603.20	1987.20
	17:45	391.68	1564.80	1956.48
	18:00	389.76	1632.00	2021.76
	18:15	382.08	1612.80	1994.88
	18:30	378.24	1632.00	2010.24
	18:45	380.16	1641.60	2021.76
	19:00	370.56	1641.60	2012.16
	19:15	372.48	1718.40	2090.88
	19:30	374.40	1804.80	2179.20
	19:45	387.84	1785.60	2173.44
	20:00	370.56	1747.20	2117.76
	20:15	362.88	1814.40	2177.28
	20:30	378.24	1804.80	2183.04
	20:45	380.16	1795.20	2175.36
	21:00	368.64	1776.00	2144.64
	21:15	362.88	1824.00	2186.88
	21:30	366.72	1843.20	2209.92
	21:45	370.56	1872.00	2242.56
	22:00	366.72	1795.20	2161.92
	22:15	360.96	1824.00	2184.96
	22:30	362.88	1814.40	2177.28
	22:45	357.12	1852.80	2209.92
	23:00	353.28	1939.20	2292.48
	23:15	351.36	1718.40	2069.76
	23:30	343.68	1795.20	2138.88
	23:45	355.20	1920.00	2275.20
1/26/2010	0:00	359.04	1766.40	2125.44
	0:15	328.32	1756.80	2085.12
	0:30	324.48	1833.60	2158.08
	0:45	320.64	1785.60	2106.24
	1:00	307.20	1699.20	2006.40
	1:15	328.32	1881.60	2209.92
	1:30	316.80	1689.60	2006.40
	1:45	309.12	1670.40	1979.52
	2:00	309.12	1670.40	1979.52
	2:15	320.64	1776.00	2096.64
	2:30	324.48	1699.20	2023.68
	2:45	330.24	1747.20	2077.44
	3:00	322.56	1584.00	1906.56
	3:15	330.24	1545.60	1875.84
	3:30	314.88	1516.80	1831.68
	3:45	307.20	1507.20	1814.40
	4:00	301.44	1468.80	1770.24
	4:15	320.64	1459.20	1779.84
	4:30	316.80	1478.40	1795.20
	4:45	295.68	1459.20	1754.88
	5:00	297.60	1449.60	1747.20
	5:15	301.44	1593.60	1895.04
	5:30	303.36	1612.80	1916.16
	5:45	299.52	1564.80	1864.32
	6:00	303.36	1670.40	1973.76
	6:15	330.24	1612.80	1943.04
	6:30	330.24	1622.40	1952.64
	6:45	334.08	1680.00	2014.08
	7:00	330.24	1699.20	2029.44
	7:15	370.56	1728.00	2098.56
	7:30	387.84	1756.80	2144.64
	7:45	393.60	1756.80	2150.40
	8:00	385.92	1737.60	2123.52
	8:15	385.92	1747.20	2133.12
	8:30	399.36	1747.20	2146.56
	8:45	389.76	1804.80	2194.56
	9:00	357.12	1843.20	2200.32
	9:15	362.88	1795.20	2158.08
	9:30	368.64	1785.60	2154.24
	9:45	370.56	1795.20	2165.76
	10:00	362.88	1785.60	2148.48
	10:15	368.64	1804.80	2173.44

		Store A	Store B	Store A + Store B
	10:30	374.40	1756.80	2131.20
	10:45	359.04	1785.60	2144.64
	11:00	349.44	1804.80	2154.24
	11:15	359.04	1785.60	2144.64
	11:30	362.88	1996.80	2359.68
	11:45	370.56	1900.80	2271.36
	12:00	366.72	1881.60	2248.32
	12:15	370.56	1910.40	2280.96
	12:30	372.48	1872.00	2244.48
	12:45	385.92	1804.80	2190.72
	13:00	380.16	1804.80	2184.96
	13:15	368.64	1795.20	2163.84
	13:30	370.56	1584.00	1954.56
	13:45	385.92	1584.00	1969.92
	14:00	378.24	1622.40	2000.64
	14:15	372.48	1593.60	1966.08
	14:30	376.32	1660.80	2037.12
	14:45	401.28	1718.40	2119.68
	15:00	384.00	1824.00	2208.00
	15:15	389.76	1872.00	2261.76
	15:30	382.08	1785.60	2167.68
	15:45	368.64	1795.20	2163.84
	16:00	370.56	1881.60	2252.16
	16:15	378.24	1776.00	2154.24
	16:30	385.92	1651.20	2037.12
	16:45	366.72	1257.60	1624.32
	17:00	370.56	1190.40	1560.96
	17:15	384.00	1075.20	1459.20
	17:30	376.32	1344.00	1720.32
	17:45	416.64	1161.60	1578.24
	18:00	405.12	1190.40	1595.52
	18:15	385.92	1363.20	1749.12
	18:30	401.28	1766.40	2167.68
	18:45	391.68	1987.20	2378.88
	19:00	380.16	1987.20	2367.36
	19:15	382.08	2092.80	2474.88
	19:30	393.60	1958.40	2352.00
	19:45	389.76	1958.40	2348.16
	20:00	378.24	1968.00	2346.24
	20:15	382.08	1795.20	2177.28
	20:30	374.40	1785.60	2160.00
	20:45	391.68	1766.40	2158.08
	21:00	372.48	1766.40	2138.88
	21:15	374.40	1833.60	2208.00
	21:30	368.64	1891.20	2259.84
	21:45	364.80	1872.00	2236.80
	22:00	360.96	1852.80	2213.76
	22:15	364.80	1862.40	2227.20
	22:30	370.56	1824.00	2194.56
	22:45	351.36	1939.20	2290.56
	23:00	336.00	2006.40	2342.40
	23:15	337.92	1900.80	2238.72
	23:30	334.08	1910.40	2244.48
	23:45	341.76	1795.20	2136.96
1/27/2010	0:00	345.60	1785.60	2131.20
	0:15	318.72	1881.60	2200.32
	0:30	314.88	1833.60	2148.48
	0:45	305.28	1852.80	2158.08
	1:00	305.28	1881.60	2186.88
	1:15	320.64	1852.80	2173.44
	1:30	312.96	1843.20	2156.16
	1:45	311.04	1804.80	2115.84
	2:00	309.12	1852.80	2161.92
	2:15	322.56	1910.40	2232.96
	2:30	326.40	1804.80	2131.20
	2:45	339.84	1852.80	2192.64
	3:00	314.88	1862.40	2177.28
	3:15	328.32	1862.40	2190.72
	3:30	318.72	1881.60	2200.32
	3:45	307.20	1833.60	2140.80
	4:00	307.20	1852.80	2160.00
	4:15	318.72	1862.40	2181.12
	4:30	324.48	1833.60	2158.08
	4:45	309.12	1804.80	2113.92

	Store A	Store B	Store A + Store B
5:00	301.44	1776.00	2077.44
5:15	311.04	1776.00	2087.04
5:30	322.56	1852.80	2175.36
5:45	309.12	1689.60	1998.72
6:00	305.28	1718.40	2023.68
6:15	330.24	1670.40	2000.64
6:30	337.92	1622.40	1960.32
6:45	326.40	1593.60	1920.00
7:00	326.40	1651.20	1977.60
7:15	380.16	1632.00	2012.16
7:30	391.68	1689.60	2081.28
7:45	395.52	1766.40	2161.92
8:00	397.44	1737.60	2135.04
8:15	366.72	1747.20	2113.92
8:30	353.28	1766.40	2119.68
8:45	368.64	1728.00	2096.64
9:00	362.88	1747.20	2110.08
9:15	372.48	1737.60	2110.08
9:30	368.64	1718.40	2087.04
9:45	370.56	1718.40	2088.96
10:00	372.48	1718.40	2090.88
10:15	376.32	1747.20	2123.52
10:30	370.56	1680.00	2050.56
10:45	360.96	1593.60	1954.56
11:00	355.20	1622.40	1977.60
11:15	359.04	1660.80	2019.84
11:30	359.04	1756.80	2115.84
11:45	357.12	1728.00	2085.12
12:00	372.48	1795.20	2167.68
12:15	357.12	1785.60	2142.72
12:30	374.40	1728.00	2102.40
12:45	387.84	1718.40	2106.24
13:00	364.80	1718.40	2083.20
13:15	374.40	1680.00	2054.40
13:30	380.16	1708.80	2088.96
13:45	372.48	1689.60	2062.08
14:00	370.56	1603.20	1973.76
14:15	376.32	1593.60	1969.92
14:30	380.16	1632.00	2012.16
14:45	382.08	1670.40	2052.48
15:00	372.48	1747.20	2119.68
15:15	370.56	1766.40	2136.96
15:30	364.80	1728.00	2092.80
15:45	366.72	1766.40	2133.12
16:00	359.04	1756.80	2115.84
16:15	382.08	1804.80	2186.88
16:30	372.48	1756.80	2129.28
16:45	359.04	1660.80	2019.84
17:00	360.96	1660.80	2021.76
17:15	370.56	1756.80	2127.36
17:30	368.64	1728.00	2096.64
17:45	391.68	1718.40	2110.08
18:00	387.84	1814.40	2202.24
18:15	384.00	1776.00	2160.00
18:30	389.76	1718.40	2108.16
18:45	397.44	1756.80	2154.24
19:00	378.24	1420.80	1799.04
19:15	382.08	1190.40	1572.48
19:30	385.92	1641.60	2027.52
19:45	389.76	1900.80	2290.56
20:00	382.08	2083.20	2465.28
20:15	368.64	1881.60	2250.24
20:30	372.48	1795.20	2167.68
20:45	380.16	1814.40	2194.56
21:00	374.40	1776.00	2150.40
21:15	366.72	1708.80	2075.52
21:30	368.64	1660.80	2029.44
21:45	368.64	1699.20	2067.84
22:00	359.04	1660.80	2019.84
22:15	364.80	1670.40	2035.20
22:30	364.80	1670.40	2035.20
22:45	355.20	1699.20	2054.40
23:00	347.52	1670.40	2017.92
23:15	349.44	1689.60	2039.04

		Store A	Store B	Store A + Store B
	23:30	355.20	1689.60	2044.80
	23:45	357.12	1718.40	2075.52
1/28/2010	0:00	357.12	1718.40	2075.52
	0:15	330.24	1660.80	1991.04
	0:30	330.24	1699.20	2029.44
	0:45	307.20	1680.00	1987.20
	1:00	301.44	1680.00	1981.44
	1:15	316.80	1728.00	2044.80
	1:30	322.56	1123.20	1445.76
	1:45	324.48	921.60	1246.08
	2:00	311.04	940.80	1251.84
	2:15	326.40	912.00	1238.40
	2:30	332.16	912.00	1244.16
	2:45	343.68	940.80	1284.48
	3:00	318.72	921.60	1240.32
	3:15	330.24	988.80	1319.04
	3:30	328.32	1612.80	1941.12
	3:45	312.96	2035.20	2348.16
	4:00	274.56	2044.80	2319.36
	4:15	280.32	1987.20	2267.52
	4:30	322.56	1776.00	2098.56
	4:45	297.60	1046.40	1344.00
	5:00	284.16	969.60	1253.76
	5:15	309.12	1286.40	1595.52
	5:30	314.88	1065.60	1380.48
	5:45	307.20	912.00	1219.20
	6:00	311.04	931.20	1242.24
	6:15	326.40	902.40	1228.80
	6:30	332.16	912.00	1244.16
	6:45	314.88	1008.00	1322.88
	7:00	311.04	1564.80	1875.84
	7:15	351.36	2035.20	2386.56
	7:30	364.80	2083.20	2448.00
	7:45	370.56	2140.80	2511.36
	8:00	389.76	2025.60	2415.36
	8:15	360.96	1910.40	2271.36
	8:30	387.84	1948.80	2336.64
	8:45	384.00	1785.60	2169.60
	9:00	349.44	1708.80	2058.24
	9:15	336.00	1708.80	2044.80
	9:30	343.68	1296.00	1639.68
	9:45	343.68	1401.60	1745.28
	10:00	345.60	1555.20	1900.80
	10:15	334.08	1545.60	1879.68
	10:30	349.44	1536.00	1885.44
	10:45	332.16	1516.80	1848.96
	11:00	341.76	1056.00	1397.76
	11:15	347.52	1036.80	1384.32
	11:30	355.20	1766.40	2121.60
	11:45	359.04	1756.80	2115.84
	12:00	349.44	1737.60	2087.04
	12:15	359.04	1632.00	1991.04
	12:30	355.20	1718.40	2073.60
	12:45	349.44	1756.80	2106.24
	13:00	353.28	1728.00	2081.28
	13:15	345.60	1804.80	2150.40
	13:30	360.96	1699.20	2060.16
	13:45	368.64	1737.60	2106.24
	14:00	349.44	1718.40	2067.84
	14:15	351.36	1632.00	1983.36
	14:30	368.64	1766.40	2135.04
	14:45	378.24	1728.00	2106.24
	15:00	359.04	1747.20	2106.24
	15:15	359.04	1785.60	2144.64
	15:30	368.64	1689.60	2058.24
	15:45	366.72	1776.00	2142.72
	16:00	364.80	1814.40	2179.20
	16:15	359.04	1756.80	2115.84
	16:30	353.28	1814.40	2167.68
	16:45	353.28	1729.60	2082.88
	17:00	339.84	0.00	339.84
	17:15	359.04	0.00	359.04
	17:30	362.88	0.00	362.88
	17:45	347.52	0.00	347.52

		Store A	Store B	Store A + Store B
	18:00	343.68	0.00	343.68
	18:15	380.16	0.00	380.16
	18:30	366.72	0.00	366.72
	18:45	372.48	0.00	372.48
	19:00	378.24	0.00	378.24
	19:15	368.64	0.00	368.64
	19:30	372.48	0.00	372.48
	19:45	370.56	0.00	370.56
	20:00	359.04	0.00	359.04
	20:15	351.36	0.00	351.36
	20:30	355.20	0.00	355.20
	20:45	359.04	0.00	359.04
	21:00	351.36	0.00	351.36
	21:15	362.88	0.00	362.88
	21:30	355.20	0.00	355.20
	21:45	357.12	0.00	357.12
	22:00	347.52	0.00	347.52
	22:15	343.68	0.00	343.68
	22:30	362.88	0.00	362.88
	22:45	343.68	0.00	343.68
	23:00	336.00	0.00	336.00
	23:15	353.28	0.00	353.28
	23:30	337.92	0.00	337.92
	23:45	341.76	0.00	341.76
1/29/2010	0:00	336.00	0.00	336.00
	0:15	316.80	0.00	316.80
	0:30	316.80	0.00	316.80
	0:45	307.20	0.00	307.20
	1:00	295.68	0.00	295.68
	1:15	309.12	0.00	309.12
	1:30	316.80	0.00	316.80
	1:45	303.36	0.00	303.36
	2:00	299.52	0.00	299.52
	2:15	318.72	0.00	318.72
	2:30	322.56	0.00	322.56
	2:45	332.16	0.00	332.16
	3:00	320.64	0.00	320.64
	3:15	332.16	0.00	332.16
	3:30	322.56	0.00	322.56
	3:45	309.12	0.00	309.12
	4:00	305.28	0.00	305.28
	4:15	318.72	0.00	318.72
	4:30	316.80	0.00	316.80
	4:45	301.44	0.00	301.44
	5:00	291.84	0.00	291.84
	5:15	299.52	0.00	299.52
	5:30	303.36	0.00	303.36
	5:45	303.36	0.00	303.36
	6:00	307.20	0.00	307.20
	6:15	355.20	0.00	355.20
	6:30	330.24	0.00	330.24
	6:45	311.04	0.00	311.04
	7:00	301.44	0.00	301.44
	7:15	360.96	0.00	360.96
	7:30	384.00	0.00	384.00
	7:45	399.36	0.00	399.36
	8:00	382.08	0.00	382.08
	8:15	362.88	0.00	362.88
	8:30	374.40	0.00	374.40
	8:45	360.96	0.00	360.96
	9:00	372.48	0.00	372.48
	9:15	374.40	0.00	374.40
	9:30	364.80	0.00	364.80
	9:45	355.20	0.00	355.20
	10:00	366.72	0.00	366.72
	10:15	366.72	0.00	366.72
	10:30	382.08	0.00	382.08
	10:45	387.84	0.00	387.84
	11:00	366.72	0.00	366.72
	11:15	362.88	0.00	362.88
	11:30	362.88	0.00	362.88
	11:45	366.72	0.00	366.72
	12:00	368.64	48.00	416.64
	12:15	362.88	384.00	746.88

		Store A	Store B	Store A + Store B
	12:30	374.40	614.40	988.80
	12:45	395.52	1084.80	1480.32
	13:00	387.84	1113.60	1501.44
	13:15	393.60	1286.40	1680.00
	13:30	384.00	1747.20	2131.20
	13:45	405.12	1872.00	2277.12
	14:00	378.24	1440.00	1818.24
	14:15	372.48	1046.40	1418.88
	14:30	385.92	1219.20	1605.12
	14:45	403.20	1996.80	2400.00
	15:00	391.68	2140.80	2532.48
	15:15	387.84	2044.80	2432.64
	15:30	391.68	2035.20	2426.88
	15:45	407.04	1968.00	2375.04
	16:00	382.08	2016.00	2398.08
	16:15	387.84	2054.40	2442.24
	16:30	393.60	1996.80	2390.40
	16:45	368.64	1958.40	2327.04
	17:00	364.80	1929.60	2294.40
	17:15	382.08	1968.00	2350.08
	17:30	380.16	1920.00	2300.16
	17:45	372.48	1996.80	2369.28
	18:00	382.08	2025.60	2407.68
	18:15	399.36	2073.60	2472.96
	18:30	395.52	2054.40	2449.92
	18:45	393.60	1996.80	2390.40
	19:00	387.84	2073.60	2461.44
	19:15	382.08	2025.60	2407.68
	19:30	391.68	2112.00	2503.68
	19:45	403.20	2083.20	2486.40
	20:00	382.08	1948.80	2330.88
	20:15	382.08	2044.80	2426.88
	20:30	389.76	1968.00	2357.76
	20:45	376.32	2006.40	2382.72
	21:00	378.24	1929.60	2307.84
	21:15	368.64	1929.60	2298.24
	21:30	370.56	1968.00	2338.56
	21:45	374.40	2035.20	2409.60
	22:00	368.64	2054.40	2423.04
	22:15	368.64	1968.00	2336.64
	22:30	368.64	1987.20	2355.84
	22:45	353.28	2054.40	2407.68
	23:00	351.36	1987.20	2338.56
	23:15	357.12	1958.40	2315.52
	23:30	339.84	2025.60	2365.44
	23:45	349.44	2035.20	2384.64
1/30/2010	0:00	355.20	1929.60	2284.80
	0:15	332.16	1939.20	2271.36
	0:30	326.40	1977.60	2304.00
	0:45	322.56	1910.40	2232.96
	1:00	307.20	1968.00	2275.20
	1:15	318.72	2016.00	2334.72
	1:30	320.64	1968.00	2288.64
	1:45	299.52	1833.60	2133.12
	2:00	312.96	1862.40	2175.36
	2:15	328.32	1939.20	2267.52
	2:30	328.32	1824.00	2152.32
	2:45	337.92	1795.20	2133.12
	3:00	324.48	1785.60	2110.08
	3:15	343.68	1785.60	2129.28
	3:30	322.56	1785.60	2108.16
	3:45	314.88	1776.00	2090.88
	4:00	309.12	1804.80	2113.92
	4:15	324.48	1824.00	2148.48
	4:30	318.72	1824.00	2142.72
	4:45	314.88	1852.80	2167.68
	5:00	301.44	1814.40	2115.84
	5:15	322.56	1843.20	2165.76
	5:30	311.04	1833.60	2144.64
	5:45	311.04	1881.60	2192.64
	6:00	311.04	1910.40	2221.44
	6:15	307.20	2016.00	2323.20
	6:30	324.48	1910.40	2234.88
	6:45	326.40	1977.60	2304.00

		Store A	Store B	Store A + Store B
	7:00	316.80	1996.80	2313.60
	7:15	376.32	1929.60	2305.92
	7:30	391.68	2054.40	2446.08
	7:45	397.44	2092.80	2490.24
	8:00	385.92	1968.00	2353.92
	8:15	410.88	2025.60	2436.48
	8:30	389.76	2044.80	2434.56
	8:45	382.08	1996.80	2378.88
	9:00	374.40	2131.20	2505.60
	9:15	368.64	2102.40	2471.04
	9:30	374.40	1977.60	2352.00
	9:45	359.04	2121.60	2480.64
	10:00	376.32	2064.00	2440.32
	10:15	355.20	2083.20	2438.40
	10:30	364.80	2198.40	2563.20
	10:45	368.64	2169.60	2538.24
	11:00	368.64	2121.60	2490.24
	11:15	372.48	2073.60	2446.08
	11:30	376.32	2131.20	2507.52
	11:45	385.92	2131.20	2517.12
	12:00	372.48	2217.60	2590.08
	12:15	374.40	2208.00	2582.40
	12:30	370.56	2179.20	2549.76
	12:45	378.24	2121.60	2499.84
	13:00	382.08	1977.60	2359.68
	13:15	370.56	2044.80	2415.36
	13:30	382.08	2054.40	2436.48
	13:45	403.20	1900.80	2304.00
	14:00	368.64	1872.00	2240.64
	14:15	362.88	1852.80	2215.68
	14:30	374.40	1209.60	1584.00
	14:45	387.84	1564.80	1952.64
	15:00	364.80	2092.80	2457.60
	15:15	368.64	2179.20	2547.84
	15:30	366.72	2140.80	2507.52
	15:45	380.16	2179.20	2559.36
	16:00	370.56	2112.00	2482.56
	16:15	376.32	2208.00	2584.32
	16:30	376.32	2140.80	2517.12
	16:45	359.04	2083.20	2442.24
	17:00	368.64	2150.40	2519.04
	17:15	364.80	2064.00	2428.80
	17:30	378.24	2179.20	2557.44
	17:45	382.08	2140.80	2522.88
	18:00	378.24	2169.60	2547.84
	18:15	378.24	2112.00	2490.24
	18:30	395.52	2006.40	2401.92
	18:45	399.36	2035.20	2434.56
	19:00	391.68	2112.00	2503.68
	19:15	391.68	2054.40	2446.08
	19:30	399.36	2140.80	2540.16
	19:45	391.68	2246.40	2638.08
	20:00	366.72	2112.00	2478.72
	20:15	376.32	2246.40	2622.72
	20:30	378.24	2236.80	2615.04
	20:45	376.32	2217.60	2593.92
	21:00	374.40	2112.00	2486.40
	21:15	368.64	2064.00	2432.64
	21:30	360.96	2160.00	2520.96
	21:45	370.56	2102.40	2472.96
	22:00	355.20	2054.40	2409.60
	22:15	360.96	2140.80	2501.76
	22:30	355.20	2092.80	2448.00
	22:45	351.36	2073.60	2424.96
	23:00	355.20	2121.60	2476.80
	23:15	355.20	1958.40	2313.60
	23:30	349.44	2102.40	2451.84
	23:45	351.36	2131.20	2482.56
1/31/2010	0:00	355.20	2016.00	2371.20
	0:15	326.40	2016.00	2342.40
	0:30	318.72	2083.20	2401.92
	0:45	305.28	1910.40	2215.68
	1:00	309.12	1948.80	2257.92
	1:15	316.80	2083.20	2400.00

	Store A	Store B	Store A + Store B
1:30	311.04	1900.80	2211.84
1:45	314.88	1968.00	2282.88
2:00	307.20	2025.60	2332.80
2:15	326.40	1939.20	2265.60
2:30	326.40	1929.60	2256.00
2:45	332.16	1987.20	2319.36
3:00	324.48	1900.80	2225.28
3:15	341.76	1910.40	2252.16
3:30	320.64	1929.60	2250.24
3:45	328.32	1958.40	2286.72
4:00	311.04	1968.00	2279.04
4:15	322.56	1910.40	2232.96
4:30	318.72	1910.40	2229.12
4:45	291.84	1891.20	2183.04
5:00	288.00	1862.40	2150.40
5:15	299.52	1833.60	2133.12
5:30	299.52	1881.60	2181.12
5:45	301.44	1824.00	2125.44
6:00	299.52	1824.00	2123.52
6:15	307.20	1785.60	2092.80
6:30	341.76	1824.00	2165.76
6:45	332.16	1795.20	2127.36
7:00	303.36	1824.00	2127.36
7:15	355.20	1814.40	2169.60
7:30	378.24	1833.60	2211.84
7:45	382.08	1833.60	2215.68
8:00	372.48	1795.20	2167.68
8:15	357.12	1814.40	2171.52
8:30	382.08	1785.60	2167.68
8:45	397.44	1814.40	2211.84
9:00	374.40	1814.40	2188.80
9:15	378.24	1785.60	2163.84
9:30	372.48	1852.80	2225.28
9:45	384.00	1910.40	2294.40
10:00	364.80	1862.40	2227.20
10:15	360.96	1948.80	2309.76
10:30	376.32	1900.80	2277.12
10:45	368.64	1977.60	2346.24
11:00	360.96	2112.00	2472.96
11:15	370.56	1910.40	2280.96
11:30	378.24	2044.80	2423.04
11:45	364.80	2025.60	2390.40
12:00	385.92	1977.60	2363.52
12:15	370.56	2073.60	2444.16
12:30	378.24	2016.00	2394.24
12:45	372.48	1939.20	2311.68
13:00	382.08	1948.80	2330.88
13:15	378.24	1958.40	2336.64
13:30	384.00	1958.40	2342.40
13:45	407.04	1987.20	2394.24
14:00	391.68	1968.00	2359.68
14:15	372.48	1804.80	2177.28
14:30	387.84	1814.40	2202.24
14:45	387.84	1824.00	2211.84
15:00	397.44	1862.40	2259.84
15:15	389.76	1958.40	2348.16
15:30	389.76	1910.40	2300.16
15:45	408.96	1881.60	2290.56
16:00	372.48	1910.40	2282.88
16:15	372.48	2016.00	2388.48
16:30	384.00	1862.40	2246.40
16:45	374.40	1824.00	2198.40
17:00	374.40	1833.60	2208.00
17:15	391.68	1756.80	2148.48
17:30	374.40	1756.80	2131.20
17:45	376.32	1728.00	2104.32
18:00	366.72	1900.80	2267.52
18:15	374.40	1891.20	2265.60
18:30	397.44	1747.20	2144.64
18:45	384.00	1708.80	2092.80
19:00	397.44	1766.40	2163.84
19:15	395.52	1814.40	2209.92
19:30	391.68	1833.60	2225.28
19:45	395.52	1881.60	2277.12

		Store A	Store B	Store A + Store B
	20:00	382.08	1929.60	2311.68
	20:15	378.24	1843.20	2221.44
	20:30	389.76	1824.00	2213.76
	20:45	372.48	1814.40	2186.88
	21:00	374.40	1785.60	2160.00
	21:15	360.96	1804.80	2165.76
	21:30	360.96	1843.20	2204.16
	21:45	372.48	1814.40	2186.88
	22:00	360.96	1776.00	2136.96
	22:15	366.72	1814.40	2181.12
	22:30	368.64	1804.80	2173.44
	22:45	351.36	1814.40	2165.76
	23:00	345.60	1785.60	2131.20
	23:15	351.36	1756.80	2108.16
	23:30	353.28	1804.80	2158.08
	23:45	353.28	1833.60	2186.88
	0:00	349.44	1804.8	2154.24
Maximum Demand		**460.80** (1)	**2246.40** (2)	**2638.08**
			2707.20 (1) + (2)	
Automatic Savings				69.12

Seelye Rebuttal Exhibit 10

Louisville Gas and Electric Company
Plant Account 364.00 - Poles Towers and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity		Cost
E364.00-Poles, Towers, and Fixtures	1-Sep-09	BRACKET	2,292	$	964,111
E364.00-Poles, Towers, and Fixtures	1-Jan-86	CONCRETE POLES	2		15,135
E364.00-Poles, Towers, and Fixtures	1-Jan-93	CONCRETE POLES	3		34,681
E364.00-Poles, Towers, and Fixtures	31-Dec-07	CROSS ARMS	2		0
E364.00-Poles, Towers, and Fixtures	31-Jan-09	CROSS ARMS	2		2,777
E364.00-Poles, Towers, and Fixtures	19-Dec-09	CROSS ARMS	6		2,043
E364.00-Poles, Towers, and Fixtures	28-Feb-09	CROSS ARMS	20		359
E364.00-Poles, Towers, and Fixtures	31-Dec-08	CROSS ARMS	24		8,129
E364.00-Poles, Towers, and Fixtures	31-Aug-08	CROSS ARMS	215		34,341
E364.00-Poles, Towers, and Fixtures	8-Nov-06	CROSS ARMS	215		154,072
E364.00-Poles, Towers, and Fixtures	1-Jan-98	CROSS ARMS	705		166,081
E364.00-Poles, Towers, and Fixtures	1-Mar-09	CROSS ARMS	720		265,746
E364.00-Poles, Towers, and Fixtures	1-Jan-99	CROSS ARMS	800		218,633
E364.00-Poles, Towers, and Fixtures	1-Jan-94	CROSS ARMS	869		248,148
E364.00-Poles, Towers, and Fixtures	1-Jan-96	CROSS ARMS	958		293,268
E364.00-Poles, Towers, and Fixtures	1-Jan-93	CROSS ARMS	985		254,463
E364.00-Poles, Towers, and Fixtures	1-Jan-92	CROSS ARMS	1,191		256,962
E364.00-Poles, Towers, and Fixtures	1-Jan-97	CROSS ARMS	1,297		360,221
E364.00-Poles, Towers, and Fixtures	1-Jan-95	CROSS ARMS	1,356		319,162
E364.00-Poles, Towers, and Fixtures	1-Jan-02	CROSS ARMS	1,482		405,276
E364.00-Poles, Towers, and Fixtures	1-Jan-03	CROSS ARMS	1,563		389,106
E364.00-Poles, Towers, and Fixtures	1-Jan-85	CROSS ARMS	1,883		229,802
E364.00-Poles, Towers, and Fixtures	1-Jan-84	CROSS ARMS	1,906		147,829
E364.00-Poles, Towers, and Fixtures	1-Jan-91	CROSS ARMS	1,976		314,660
E364.00-Poles, Towers, and Fixtures	30-Sep-09	CROSS ARMS	2,020		871,581
E364.00-Poles, Towers, and Fixtures	1-Jan-90	CROSS ARMS	2,103		291,993
E364.00-Poles, Towers, and Fixtures	1-Jan-07	CROSS ARMS	2,117		55,471
E364.00-Poles, Towers, and Fixtures	1-Jan-87	CROSS ARMS	2,263		308,772
E364.00-Poles, Towers, and Fixtures	1-Jan-86	CROSS ARMS	2,299		313,379
E364.00-Poles, Towers, and Fixtures	1-Jan-89	CROSS ARMS	2,401		269,426
E364.00-Poles, Towers, and Fixtures	1-Jan-82	CROSS ARMS	2,497		220,141
E364.00-Poles, Towers, and Fixtures	1-Jan-01	CROSS ARMS	2,710		611,587
E364.00-Poles, Towers, and Fixtures	1-Jan-83	CROSS ARMS	2,749		222,410
E364.00-Poles, Towers, and Fixtures	1-Jan-00	CROSS ARMS	2,805		587,142
E364.00-Poles, Towers, and Fixtures	1-Jan-88	CROSS ARMS	2,849		669,436
E364.00-Poles, Towers, and Fixtures	1-Jan-08	CROSS ARMS	2,866		374,786
E364.00-Poles, Towers, and Fixtures	1-Jan-74	CROSS ARMS	2,959		105,202
E364.00-Poles, Towers, and Fixtures	1-Jan-73	CROSS ARMS	3,039		79,667
E364.00-Poles, Towers, and Fixtures	1-Jan-81	CROSS ARMS	3,050		235,579
E364.00-Poles, Towers, and Fixtures	1-Jan-72	CROSS ARMS	3,143		74,598
E364.00-Poles, Towers, and Fixtures	1-Jan-77	CROSS ARMS	3,217		142,441
E364.00-Poles, Towers, and Fixtures	1-Jan-75	CROSS ARMS	3,267		121,363

Louisville Gas and Electric Company
Plant Account 364.00 - Poles Towers and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-78	CROSS ARMS	3,300	172,583
E364.00-Poles, Towers, and Fixtures	1-Jan-76	CROSS ARMS	3,350	144,111
E364.00-Poles, Towers, and Fixtures	1-Jan-71	CROSS ARMS	3,447	78,176
E364.00-Poles, Towers, and Fixtures	1-Jan-79	CROSS ARMS	3,449	208,153
E364.00-Poles, Towers, and Fixtures	1-Jan-04	CROSS ARMS	3,572	465,424
E364.00-Poles, Towers, and Fixtures	1-Jan-66	CROSS ARMS	3,609	49,208
E364.00-Poles, Towers, and Fixtures	1-Jan-70	CROSS ARMS	3,609	75,887
E364.00-Poles, Towers, and Fixtures	1-Jan-80	CROSS ARMS	3,770	260,208
E364.00-Poles, Towers, and Fixtures	1-Jan-68	CROSS ARMS	3,821	60,798
E364.00-Poles, Towers, and Fixtures	1-Jan-67	CROSS ARMS	3,969	58,998
E364.00-Poles, Towers, and Fixtures	1-Jan-69	CROSS ARMS	4,071	68,844
E364.00-Poles, Towers, and Fixtures	1-Jan-65	CROSS ARMS	4,326	55,816
E364.00-Poles, Towers, and Fixtures	1-Jan-05	CROSS ARMS	4,865	263,534
E364.00-Poles, Towers, and Fixtures	1-Jan-63	CROSS ARMS	6,524	94,439
E364.00-Poles, Towers, and Fixtures	1-Jan-06	CROSS ARMS	7,103	331,238
E364.00-Poles, Towers, and Fixtures	1-Jan-57	CROSS ARMS	26,164	282,868
E364.00-Poles, Towers, and Fixtures	1-Jan-07	GUY	1	1
E364.00-Poles, Towers, and Fixtures	1-Jan-04	GUY	4	46,575
E364.00-Poles, Towers, and Fixtures	10-Dec-09	GUY	8	3,429
E364.00-Poles, Towers, and Fixtures	1-Jan-34	GUY	46	5,343
E364.00-Poles, Towers, and Fixtures	1-Jan-03	GUY	68	68,331
E364.00-Poles, Towers, and Fixtures	1-Sep-09	GUY	106	47,882
E364.00-Poles, Towers, and Fixtures	1-Jan-00	GUY	239	35,503
E364.00-Poles, Towers, and Fixtures	1-Jan-06	GUY	383	1,787
E364.00-Poles, Towers, and Fixtures	17-Dec-09	GUY	583	134,943
E364.00-Poles, Towers, and Fixtures	1-Jan-98	GUY	617	335,294
E364.00-Poles, Towers, and Fixtures	1-Jan-02	GUY	757	236,794
E364.00-Poles, Towers, and Fixtures	1-Jan-99	GUY	790	218,315
E364.00-Poles, Towers, and Fixtures	1-Jan-96	GUY	922	564,939
E364.00-Poles, Towers, and Fixtures	1-Jan-94	GUY	969	550,583
E364.00-Poles, Towers, and Fixtures	1-Jan-97	GUY	996	560,869
E364.00-Poles, Towers, and Fixtures	1-Jan-93	GUY	1,173	631,208
E364.00-Poles, Towers, and Fixtures	1-Jan-95	GUY	1,500	688,343
E364.00-Poles, Towers, and Fixtures	1-Jan-92	GUY	1,536	695,326
E364.00-Poles, Towers, and Fixtures	1-Jan-84	GUY	1,748	458,284
E364.00-Poles, Towers, and Fixtures	1-Jan-87	GUY	1,911	507,991
E364.00-Poles, Towers, and Fixtures	1-Jan-85	GUY	1,932	464,428
E364.00-Poles, Towers, and Fixtures	1-Jan-86	GUY	2,148	564,403
E364.00-Poles, Towers, and Fixtures	1-Jan-82	GUY	2,269	697,951
E364.00-Poles, Towers, and Fixtures	1-Jan-83	GUY	2,282	812,933
E364.00-Poles, Towers, and Fixtures	1-Jan-90	GUY	2,285	707,643
E364.00-Poles, Towers, and Fixtures	1-Jan-91	GUY	2,313	771,654

Louisville Gas and Electric Company
Plant Account 364.00 - Poles Towers and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-81	GUY	2,488	648,250
E364.00-Poles, Towers, and Fixtures	1-Jan-88	GUY	2,645	616,320
E364.00-Poles, Towers, and Fixtures	1-Jan-89	GUY	2,747	742,773
E364.00-Poles, Towers, and Fixtures	1-Jan-77	GUY	2,821	421,250
E364.00-Poles, Towers, and Fixtures	1-Jan-80	GUY	2,842	620,267
E364.00-Poles, Towers, and Fixtures	1-Jan-74	GUY	2,846	326,440
E364.00-Poles, Towers, and Fixtures	1-Jan-75	GUY	2,998	376,527
E364.00-Poles, Towers, and Fixtures	1-Jan-70	GUY	3,178	228,211
E364.00-Poles, Towers, and Fixtures	1-Jan-76	GUY	3,210	451,230
E364.00-Poles, Towers, and Fixtures	1-Jan-68	GUY	3,485	206,581
E364.00-Poles, Towers, and Fixtures	1-Jan-72	GUY	3,520	302,873
E364.00-Poles, Towers, and Fixtures	1-Jan-79	GUY	3,539	704,369
E364.00-Poles, Towers, and Fixtures	1-Jan-73	GUY	3,553	301,250
E364.00-Poles, Towers, and Fixtures	1-Jan-78	GUY	3,641	667,743
E364.00-Poles, Towers, and Fixtures	1-Jan-71	GUY	3,974	301,432
E364.00-Poles, Towers, and Fixtures	1-Jan-67	GUY	3,986	212,001
E364.00-Poles, Towers, and Fixtures	1-Jan-69	GUY	4,032	249,329
E364.00-Poles, Towers, and Fixtures	1-Jan-65	GUY	4,555	214,654
E364.00-Poles, Towers, and Fixtures	1-Jan-66	GUY	4,901	194,315
E364.00-Poles, Towers, and Fixtures	1-Jan-01	GUY	5,444	207,871
E364.00-Poles, Towers, and Fixtures	1-Jan-47	GUY	6,419	96,722
E364.00-Poles, Towers, and Fixtures	1-Jan-63	GUY	8,278	401,831
E364.00-Poles, Towers, and Fixtures	1-Jan-53	GUY	12,148	282,307
E364.00-Poles, Towers, and Fixtures	1-Jan-42	GUY	24,406	11,107
E364.00-Poles, Towers, and Fixtures	1-Jan-57	GUY	26,677	831,370
E364.00-Poles, Towers, and Fixtures	1-Jan-05	GUY	173	79,536
E364.00-Poles, Towers, and Fixtures	1-Jan-08	GUY	218	8,734
E364.00-Poles, Towers, and Fixtures	1-Jan-07	GUY	280	10,090
E364.00-Poles, Towers, and Fixtures	1-Jan-06	GUY	982	257,781
E364.00-Poles, Towers, and Fixtures	1-Jan-03	H-BEAM STEEL GUY	1	10,647
E364.00-Poles, Towers, and Fixtures	1-Jan-06	H-BEAM STEEL GUY	1	23,275
E364.00-Poles, Towers, and Fixtures	31-Aug-08	H-BEAM STEEL GUY	3	12,354
E364.00-Poles, Towers, and Fixtures	1-Jan-96	H-BEAM STEEL GUY	3	21,356
E364.00-Poles, Towers, and Fixtures	1-Jan-99	H-BEAM STEEL GUY	4	7,007
E364.00-Poles, Towers, and Fixtures	1-Jan-94	H-BEAM STEEL GUY	4	33,139
E364.00-Poles, Towers, and Fixtures	1-Jan-92	H-BEAM STEEL GUY	5	25,519
E364.00-Poles, Towers, and Fixtures	1-Jan-04	H-BEAM STEEL GUY	6	83,281
E364.00-Poles, Towers, and Fixtures	1-Jan-00	H-BEAM STEEL GUY	6	116,096
E364.00-Poles, Towers, and Fixtures	1-Jan-93	H-BEAM STEEL GUY	7	44,542
E364.00-Poles, Towers, and Fixtures	1-Jan-84	H-BEAM STEEL GUY	8	23,039
E364.00-Poles, Towers, and Fixtures	1-Jan-83	H-BEAM STEEL GUY	8	25,080
E364.00-Poles, Towers, and Fixtures	1-Jan-91	H-BEAM STEEL GUY	8	33,989

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Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-80	H-BEAM STEEL GUY	9	23,303
E364.00-Poles, Towers, and Fixtures	1-Jan-08	H-BEAM STEEL GUY	10	10,179
E364.00-Poles, Towers, and Fixtures	1-Jan-82	H-BEAM STEEL GUY	10	31,402
E364.00-Poles, Towers, and Fixtures	1-Jan-87	H-BEAM STEEL GUY	11	33,132
E364.00-Poles, Towers, and Fixtures	1-Jan-90	H-BEAM STEEL GUY	11	49,774
E364.00-Poles, Towers, and Fixtures	1-Jan-97	H-BEAM STEEL GUY	11	96,854
E364.00-Poles, Towers, and Fixtures	1-Jan-79	H-BEAM STEEL GUY	12	26,380
E364.00-Poles, Towers, and Fixtures	1-Jan-81	H-BEAM STEEL GUY	12	32,161
E364.00-Poles, Towers, and Fixtures	1-Jan-98	H-BEAM STEEL GUY	13	30,465
E364.00-Poles, Towers, and Fixtures	1-Jan-86	H-BEAM STEEL GUY	14	45,401
E364.00-Poles, Towers, and Fixtures	1-Jan-85	H-BEAM STEEL GUY	15	46,082
E364.00-Poles, Towers, and Fixtures	1-Jan-95	H-BEAM STEEL GUY	18	94,223
E364.00-Poles, Towers, and Fixtures	1-Jan-88	H-BEAM STEEL GUY	20	65,228
E364.00-Poles, Towers, and Fixtures	1-Jan-02	H-BEAM STEEL GUY	21	190,291
E364.00-Poles, Towers, and Fixtures	1-Jan-01	H-BEAM STEEL GUY	22	20,780
E364.00-Poles, Towers, and Fixtures	1-Jan-89	H-BEAM STEEL GUY	23	95,144
E364.00-Poles, Towers, and Fixtures	1-Jan-00	MISCELLANEOUS EQUIPMENT	1	0
E364.00-Poles, Towers, and Fixtures	1-Jan-04	PLATFORM	1	0
E364.00-Poles, Towers, and Fixtures	1-Jan-02	PLATFORMS NEW (05491)	1	13,151
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 100 FT	1	49
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 100 FT	1	10,902
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 100 FT	2	8,337
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 100 FT	3	113
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 105 FT	1	242
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 105 FT	1	3,010
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 105 FT	1	6,943
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 105 FT	1	11,888
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 105 FT	1	17,511
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 110 FT	4	368
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 25 FT	1	555
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 25 FT	1	633
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 25 FT	1	870
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 25 FT	1	1,185
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 25 FT	1	3,617
E364.00-Poles, Towers, and Fixtures	1-Mar-09	POLE WOOD 25 FT	2	919
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 25 FT	2	2,143
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 25 FT	6	2,961
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 25 FT	38	14,639
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 25 FT	43	13,543
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 25 FT	53	10,045
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 25 FT	54	6,922
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 25 FT	55	7,397

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E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 25 FT	57	11,765
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 25 FT	57	15,426
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 25 FT	58	12,871
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 25 FT	67	10,624
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 25 FT	73	11,057
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 25 FT	79	4,379
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 25 FT	79	5,801
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 25 FT	82	4,533
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 25 FT	82	5,201
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 25 FT	86	7,582
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 25 FT	91	9,726
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 25 FT	92	5,498
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 25 FT	107	5,123
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 25 FT	139	10,802
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 25 FT	189	9,256
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD 25 FT	553	11,146
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 25 FT	1,028	27,386
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 25 FT	1,225	38,335
E364.00-Poles, Towers, and Fixtures	31-Dec-08	POLE WOOD 30 FT	1	482
E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 30 FT	1	6,190
E364.00-Poles, Towers, and Fixtures	31-Mar-08	POLE WOOD 30 FT	5	11,252
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 30 FT	6	2,831
E364.00-Poles, Towers, and Fixtures	28-Feb-08	POLE WOOD 30 FT	13	30,261
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 30 FT	19	14,631
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 30 FT	52	29,135
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 30 FT	55	73,060
E364.00-Poles, Towers, and Fixtures	1-Mar-09	POLE WOOD 30 FT	66	71,455
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 30 FT	77	50,096
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 30 FT	95	152,774
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 30 FT	105	29,460
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 30 FT	107	78,453
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 30 FT	125	127,126
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 30 FT	127	80,151
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 30 FT	133	237,894
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 30 FT	135	120,048
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 30 FT	200	248,241
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 30 FT	202	221,015
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 30 FT	245	200,943
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 30 FT	252	270,974
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 30 FT	257	262,037
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 30 FT	271	216,077
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 30 FT	296	234,482

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E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 30 FT	320	208,095
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 30 FT	323	20,698
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 30 FT	339	153,869
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 30 FT	349	135,326
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 30 FT	354	119,398
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 30 FT	357	175,797
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 30 FT	359	176,044
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 30 FT	361	183,662
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 30 FT	364	150,296
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 30 FT	382	183,179
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 30 FT	390	26,963
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 30 FT	396	112,282
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 30 FT	415	237,136
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 30 FT	416	207,035
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 30 FT	434	75,397
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 30 FT	479	75,718
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 30 FT	484	20,613
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 30 FT	490	97,976
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 30 FT	490	115,821
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 30 FT	491	36,884
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 30 FT	491	128,933
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 30 FT	497	56,378
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 30 FT	498	92,342
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 30 FT	547	39,231
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 30 FT	570	74,319
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 30 FT	617	57,128
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 30 FT	656	41,549
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 30 FT	684	66,530
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 30 FT	726	57,357
E364.00-Poles, Towers, and Fixtures	28-Feb-08	POLE WOOD 35 FT	2	7,821
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 35 FT	5	9,859
E364.00-Poles, Towers, and Fixtures	31-Mar-08	POLE WOOD 35 FT	5	16,534
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 35 FT	6	1,269
E364.00-Poles, Towers, and Fixtures	1-Mar-08	POLE WOOD 35 FT	7	20,205
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 35 FT	28	43,095
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 35 FT	80	95,902
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 35 FT	94	103,706
E364.00-Poles, Towers, and Fixtures	1-Mar-09	POLE WOOD 35 FT	104	163,233
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 35 FT	116	284,718
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD 35 FT	156	6,260
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 35 FT	205	224,958
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 35 FT	222	281,047

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E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 35 FT	224	364,933
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 35 FT	226	252,812
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 35 FT	237	215,289
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 35 FT	247	136,956
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 35 FT	248	138,316
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 35 FT	253	133,857
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 35 FT	257	74,215
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 35 FT	261	82,656
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 35 FT	264	267,559
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 35 FT	268	106,724
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 35 FT	271	155,441
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 35 FT	295	348,547
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 35 FT	297	71,815
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 35 FT	298	160,509
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 35 FT	310	158,798
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 35 FT	313	75,562
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 35 FT	323	144,843
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 35 FT	335	114,027
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 35 FT	348	62,272
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 35 FT	348	332,641
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 35 FT	353	161,624
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 35 FT	353	446,626
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 35 FT	354	67,760
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 35 FT	369	265,441
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 35 FT	371	56,999
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 35 FT	373	520,829
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 35 FT	379	233,900
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 35 FT	380	487,536
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 35 FT	388	431,661
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 35 FT	398	209,074
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 35 FT	653	54,806
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 35 FT	711	49,680
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 35 FT	749	65,454
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 35 FT	773	103,082
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 35 FT	841	79,373
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 35 FT	844	94,899
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 35 FT	845	82,811
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 35 FT	860	103,095
E364.00-Poles, Towers, and Fixtures	31-Aug-09	POLE WOOD 35 FT	998	1,426,601
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 35 FT	1,158	89,714
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 35 FT	1,195	66,800
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 35 FT	2,010	128,666

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E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 40 FT	2	18,457
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 40 FT	10	17,732
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 40 FT	11	26,947
E364.00-Poles, Towers, and Fixtures	28-Feb-08	POLE WOOD 40 FT	11	38,217
E364.00-Poles, Towers, and Fixtures	31-Mar-08	POLE WOOD 40 FT	13	57,420
E364.00-Poles, Towers, and Fixtures	1-Mar-08	POLE WOOD 40 FT	28	81,331
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 40 FT	38	88,539
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 40 FT	67	128,823
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 40 FT	104	141,008
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 40 FT	128	136,129
E364.00-Poles, Towers, and Fixtures	1-Mar-09	POLE WOOD 40 FT	168	361,329
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 40 FT	234	429,560
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 40 FT	251	221,890
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 40 FT	338	555,901
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 40 FT	352	924,794
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 40 FT	363	327,917
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 40 FT	365	558,564
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 40 FT	382	667,280
E364.00-Poles, Towers, and Fixtures	30-Sep-09	POLE WOOD 40 FT	390	806,337
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 40 FT	398	418,960
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 40 FT	449	910,385
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 40 FT	525	660,618
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 40 FT	540	746,269
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 40 FT	543	804,318
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 40 FT	701	738,786
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 40 FT	954	793,773
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 40 FT	1,014	768,738
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 40 FT	1,104	622,181
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 40 FT	1,265	827,511
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 40 FT	1,313	861,826
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 40 FT	1,391	842,080
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 40 FT	1,483	599,518
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 40 FT	1,483	734,535
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 40 FT	1,484	159,229
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 40 FT	1,492	386,006
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 40 FT	1,520	913,901
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 40 FT	1,524	168,374
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 40 FT	1,565	993,322
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 40 FT	1,605	860,347
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 40 FT	1,605	1,009,388
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 40 FT	1,641	587,694
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 40 FT	1,647	161,772

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E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 40 FT	1,649	493,104
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 40 FT	1,690	204,314
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 40 FT	1,700	491,356
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 40 FT	1,746	245,606
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 40 FT	1,747	260,510
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 40 FT	1,759	885,941
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 40 FT	1,773	206,911
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 40 FT	1,844	90,661
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 40 FT	1,849	319,021
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 40 FT	1,902	533,367
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 40 FT	1,910	142,482
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 40 FT	2,322	216,739
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 40 FT	8,709	742,955
E364.00-Poles, Towers, and Fixtures	31-Dec-07	POLE WOOD 45 FT	1	0
E364.00-Poles, Towers, and Fixtures	19-Dec-09	POLE WOOD 45 FT	1	2,315
E364.00-Poles, Towers, and Fixtures	30-Jun-09	POLE WOOD 45 FT	1	3,327
E364.00-Poles, Towers, and Fixtures	31-Aug-09	POLE WOOD 45 FT	2	6,653
E364.00-Poles, Towers, and Fixtures	31-Jan-09	POLE WOOD 45 FT	5	19,136
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 45 FT	8	25,438
E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 45 FT	10	120,397
E364.00-Poles, Towers, and Fixtures	28-Feb-08	POLE WOOD 45 FT	16	66,658
E364.00-Poles, Towers, and Fixtures	31-Mar-08	POLE WOOD 45 FT	16	88,157
E364.00-Poles, Towers, and Fixtures	14-Dec-09	POLE WOOD 45 FT	29	51,000
E364.00-Poles, Towers, and Fixtures	31-Dec-08	POLE WOOD 45 FT	41	99,895
E364.00-Poles, Towers, and Fixtures	1-Mar-09	POLE WOOD 45 FT	143	373,659
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 45 FT	154	215,718
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 45 FT	156	114,118
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 45 FT	183	22,832
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 45 FT	190	22,297
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 45 FT	235	28,851
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 45 FT	240	34,173
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 45 FT	249	34,184
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 45 FT	254	1,333,145
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 45 FT	306	236,188
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 45 FT	317	59,637
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 45 FT	333	243,288
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 45 FT	336	241,014
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 45 FT	340	124,252
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 45 FT	344	95,832
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 45 FT	349	70,934
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 45 FT	351	57,052
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 45 FT	353	262,526

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E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 45 FT	369	113,232
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 45 FT	369	441,478
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 45 FT	384	68,876
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 45 FT	398	882,677
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 45 FT	401	550,497
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 45 FT	406	139,373
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 45 FT	426	401,015
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 45 FT	430	1,116,967
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 45 FT	441	190,651
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 45 FT	441	672,845
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 45 FT	444	302,172
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 45 FT	452	107,991
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 45 FT	453	362,660
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 45 FT	454	643,689
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 45 FT	460	237,041
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 45 FT	471	225,947
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 45 FT	475	352,602
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 45 FT	476	409,068
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 45 FT	487	300,839
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 45 FT	494	732,824
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 45 FT	504	301,498
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 45 FT	514	900,022
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 45 FT	631	417,434
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 45 FT	631	757,152
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 45 FT	649	762,657
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 45 FT	662	1,021,083
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 45 FT	738	1,126,567
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 45 FT	816	1,084,805
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 45 FT	846	88,854
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 45 FT	1,184	1,529,444
E364.00-Poles, Towers, and Fixtures	30-Sep-09	POLE WOOD 45 FT	1,185	2,458,112
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 50 FT	1	4,038
E364.00-Poles, Towers, and Fixtures	28-Feb-08	POLE WOOD 50 FT	2	8,494
E364.00-Poles, Towers, and Fixtures	28-Feb-09	POLE WOOD 50 FT	3	4,180
E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 50 FT	3	40,804
E364.00-Poles, Towers, and Fixtures	1-Dec-09	POLE WOOD 50 FT	4	18,615
E364.00-Poles, Towers, and Fixtures	31-Mar-08	POLE WOOD 50 FT	6	47,406
E364.00-Poles, Towers, and Fixtures	1-Mar-08	POLE WOOD 50 FT	14	48,790
E364.00-Poles, Towers, and Fixtures	1-Mar-09	POLE WOOD 50 FT	22	82,703
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 50 FT	33	82,433
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 50 FT	38	32,819
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 50 FT	41	231,459

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E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 50 FT	67	136,751
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 50 FT	90	10,907
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 50 FT	94	177,735
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 50 FT	99	206,999
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 50 FT	104	147,709
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 50 FT	105	176,970
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 50 FT	107	16,406
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 50 FT	115	294,847
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 50 FT	118	100,707
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 50 FT	119	110,566
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 50 FT	121	25,072
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 50 FT	125	29,524
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 50 FT	127	109,772
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 50 FT	128	139,139
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 50 FT	129	184,445
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 50 FT	134	120,106
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 50 FT	142	82,328
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 50 FT	142	274,895
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 50 FT	150	40,842
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 50 FT	151	337,092
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 50 FT	152	32,696
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 50 FT	155	60,703
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 50 FT	156	77,065
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 50 FT	157	55,393
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 50 FT	158	63,880
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 50 FT	159	309,950
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 50 FT	161	142,271
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 50 FT	170	135,341
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 50 FT	172	192,177
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 50 FT	174	23,866
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 50 FT	179	119,092
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 50 FT	183	30,281
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 50 FT	184	38,351
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 50 FT	190	138,256
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 50 FT	190	176,467
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 50 FT	195	31,137
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 50 FT	195	198,984
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 50 FT	198	141,776
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 50 FT	199	84,216
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 50 FT	213	320,673
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 50 FT	217	312,356
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 50 FT	242	490,916

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E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 50 FT	263	37,552
E364.00-Poles, Towers, and Fixtures	31-Aug-09	POLE WOOD 50 FT	408	1,156,163
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 50 FT	452	485,158
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 50 FT	1,011	131,541
E364.00-Poles, Towers, and Fixtures	31-Oct-08	POLE WOOD 55 FT	1	0
E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 55 FT	1	13,970
E364.00-Poles, Towers, and Fixtures	31-Aug-09	POLE WOOD 55 FT	3	13,756
E364.00-Poles, Towers, and Fixtures	1-Dec-09	POLE WOOD 55 FT	3	16,159
E364.00-Poles, Towers, and Fixtures	31-Mar-08	POLE WOOD 55 FT	3	31,156
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 55 FT	7	11,752
E364.00-Poles, Towers, and Fixtures	1-Mar-08	POLE WOOD 55 FT	13	131,397
E364.00-Poles, Towers, and Fixtures	1-Mar-09	POLE WOOD 55 FT	15	65,760
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD 55 FT	17	1,997
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 55 FT	17	53,419
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 55 FT	20	150,208
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 55 FT	21	58,730
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 55 FT	30	69,765
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 55 FT	32	6,299
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 55 FT	34	17,241
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 55 FT	35	71,596
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 55 FT	36	11,234
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 55 FT	36	88,491
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 55 FT	36	96,742
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 55 FT	37	10,761
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 55 FT	39	53,683
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 55 FT	42	8,875
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 55 FT	43	75,429
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 55 FT	43	86,147
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 55 FT	43	105,009
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 55 FT	44	11,157
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 55 FT	44	17,983
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 55 FT	45	11,170
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 55 FT	49	9,361
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 55 FT	56	39,743
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 55 FT	56	97,397
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 55 FT	56	101,026
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 55 FT	58	65,460
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 55 FT	60	70,902
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 55 FT	61	27,959
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 55 FT	62	12,828
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 55 FT	66	334,360
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 55 FT	68	42,040

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E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 55 FT	72	78,281
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 55 FT	73	37,535
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 55 FT	76	14,128
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 55 FT	80	81,872
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 55 FT	83	75,880
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 55 FT	84	70,585
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 55 FT	85	134,039
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 55 FT	87	184,566
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 55 FT	88	48,472
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 55 FT	88	95,461
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 55 FT	89	99,743
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 55 FT	90	127,863
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 55 FT	113	135,489
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 55 FT	114	147,882
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 55 FT	129	118,785
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 55 FT	136	246,481
E364.00-Poles, Towers, and Fixtures	31-Jan-09	POLE WOOD 55 FT	143	551,181
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 55 FT	300	46,984
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 55 FT	552	91,326
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 60 FT	1	0
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 60 FT	1	6,084
E364.00-Poles, Towers, and Fixtures	31-Oct-08	POLE WOOD 60 FT	2	3,577
E364.00-Poles, Towers, and Fixtures	28-Feb-08	POLE WOOD 60 FT	3	6,114
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 60 FT	5	17,313
E364.00-Poles, Towers, and Fixtures	1-Mar-09	POLE WOOD 60 FT	5	26,216
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 60 FT	6	19,457
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 60 FT	8	21,850
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 60 FT	10	32,793
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 60 FT	10	41,477
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 60 FT	11	6,752
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 60 FT	12	22,745
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 60 FT	14	32,978
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 60 FT	14	39,801
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 60 FT	15	9,143
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 60 FT	15	38,970
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 60 FT	17	17,721
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 60 FT	18	43,156
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 60 FT	21	47,105
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 60 FT	22	112,463
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 60 FT	23	17,403
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 60 FT	24	33,653
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 60 FT	25	8,994

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Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 60 FT	25	14,610
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 60 FT	26	8,646
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 60 FT	26	21,866
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 60 FT	31	7,222
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 60 FT	31	8,445
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 60 FT	31	37,735
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 60 FT	31	455,336
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 60 FT	33	30,100
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 60 FT	33	49,581
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 60 FT	34	48,441
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 60 FT	35	52,585
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 60 FT	36	24,213
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 60 FT	36	250,234
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 60 FT	37	8,711
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 60 FT	38	12,891
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 60 FT	38	21,732
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 60 FT	40	9,606
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 60 FT	42	71,295
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 60 FT	45	55,192
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 60 FT	47	66,869
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 60 FT	49	16,268
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 60 FT	49	194,645
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD 60 FT	51	5,383
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 60 FT	53	32,665
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 60 FT	56	62,684
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 60 FT	61	15,125
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 60 FT	61	52,375
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 60 FT	80	111,722
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 60 FT	166	30,104
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 60 FT	243	50,326
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 65 FT	1	0
E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 65 FT	1	5,285
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 65 FT	1	6,073
E364.00-Poles, Towers, and Fixtures	31-Mar-08	POLE WOOD 65 FT	1	12,804
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 65 FT	2	5,750
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 65 FT	2	8,859
E364.00-Poles, Towers, and Fixtures	28-Feb-08	POLE WOOD 65 FT	2	26,623
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 65 FT	3	16,488
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 65 FT	3	21,924
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 65 FT	4	8,168
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 65 FT	4	104,263
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 65 FT	5	28,892

Louisville Gas and Electric Company
Plant Account 364.00 - Poles Towers and Fixtures
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Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 65 FT	6	505
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 65 FT	6	32,062
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 65 FT	7	25,429
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 65 FT	8	31,800
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 65 FT	9	6,349
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 65 FT	10	11,774
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 65 FT	10	35,805
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 65 FT	10	74,890
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 65 FT	11	2,708
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 65 FT	11	2,919
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 65 FT	12	3,853
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 65 FT	12	5,010
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 65 FT	12	6,806
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 65 FT	12	10,719
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 65 FT	12	12,984
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 65 FT	12	24,913
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 65 FT	13	4,705
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 65 FT	13	24,513
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 65 FT	13	26,783
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 65 FT	14	18,555
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 65 FT	14	28,418
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 65 FT	15	42,259
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 65 FT	17	67,854
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 65 FT	17	139,099
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 65 FT	18	41,173
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 65 FT	18	76,112
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 65 FT	19	15,990
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 65 FT	20	33,081
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 65 FT	21	5,855
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 65 FT	22	4,266
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 65 FT	23	4,173
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 65 FT	24	7,088
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 65 FT	24	13,858
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 65 FT	25	199,466
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 65 FT	26	47,209
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 65 FT	26	53,529
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 65 FT	30	11,098
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 65 FT	31	12,210
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 65 FT	36	68,412
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 65 FT	128	32,290
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 70 FT	1	1,601
E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 70 FT	1	34,098

Louisville Gas and Electric Company
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Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 70 FT	2	654
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 70 FT	2	12,712
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 70 FT	2	14,022
E364.00-Poles, Towers, and Fixtures	28-Feb-08	POLE WOOD 70 FT	2	14,178
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 70 FT	2	14,648
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 70 FT	3	1,067
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 70 FT	3	1,518
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 70 FT	3	1,715
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 70 FT	3	8,149
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 70 FT	3	14,387
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 70 FT	3	15,277
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 70 FT	3	15,570
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 70 FT	3	18,835
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 70 FT	3	22,288
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 70 FT	3	39,485
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 70 FT	4	2,755
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 70 FT	4	11,050
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 70 FT	5	1,696
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 70 FT	5	1,765
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 70 FT	5	5,180
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 70 FT	5	9,989
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 70 FT	5	12,114
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 70 FT	5	28,491
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 70 FT	6	5,010
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 70 FT	6	5,379
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 70 FT	6	15,400
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 70 FT	6	15,636
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 70 FT	7	19,042
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 70 FT	7	24,394
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 70 FT	8	3,425
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 70 FT	8	21,211
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 70 FT	9	13,967
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 70 FT	9	27,718
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 70 FT	11	4,358
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 70 FT	11	8,583
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 70 FT	11	25,895
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 70 FT	12	73,144
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 70 FT	13	3,613
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 70 FT	15	233,329
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 70 FT	18	8,355
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 70 FT	23	17,378
E364.00-Poles, Towers, and Fixtures	16-Jun-09	POLE WOOD 70 FT	38	409,281

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Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 70 FT	45	12,926
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 75 FT	1	452
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 75 FT	1	666
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 75 FT	1	857
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 75 FT	1	1,365
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 75 FT	1	1,547
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 75 FT	1	2,659
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 75 FT	1	2,838
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 75 FT	1	4,970
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 75 FT	1	6,456
E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 75 FT	1	47,039
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD 75 FT	2	0
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 75 FT	2	922
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 75 FT	2	3,648
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 75 FT	2	4,097
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 75 FT	2	6,316
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 75 FT	2	9,946
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 75 FT	2	11,526
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 75 FT	3	3,148
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 75 FT	3	3,826
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 75 FT	3	6,759
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 75 FT	3	9,679
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 75 FT	3	18,330
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 75 FT	3	20,381
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 75 FT	4	2,049
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 75 FT	4	12,163
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 75 FT	4	13,236
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 75 FT	4	26,536
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 75 FT	4	31,656
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 75 FT	5	1,399
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 75 FT	5	2,439
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 75 FT	5	16,491
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 75 FT	5	19,466
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 75 FT	5	22,350
E364.00-Poles, Towers, and Fixtures	28-Feb-08	POLE WOOD 75 FT	5	37,627
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 75 FT	7	3,138
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 75 FT	7	7,976
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 75 FT	8	17,010
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 75 FT	8	168,641
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 75 FT	9	5,361
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 75 FT	10	1,532
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 75 FT	11	70,319

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Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 75 FT	17	219,886
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 75 FT	24	7,798
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 80 FT	1	0
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 80 FT	1	484
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 80 FT	1	493
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 80 FT	1	1,372
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 80 FT	1	1,490
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 80 FT	1	3,466
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 80 FT	1	5,603
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 80 FT	1	7,613
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 80 FT	2	0
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 80 FT	2	918
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 80 FT	2	1,087
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 80 FT	2	1,197
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 80 FT	2	1,408
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 80 FT	2	6,178
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 80 FT	2	6,787
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 80 FT	2	7,235
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 80 FT	2	15,060
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 80 FT	2	21,756
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 80 FT	2	83,930
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 80 FT	3	3,369
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 80 FT	3	9,230
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 80 FT	3	13,129
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 80 FT	4	2,126
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 80 FT	4	4,672
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 80 FT	4	15,655
E364.00-Poles, Towers, and Fixtures	28-Feb-08	POLE WOOD 80 FT	4	63,811
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 80 FT	5	3,336
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 80 FT	5	42,804
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 80 FT	7	2,799
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 80 FT	7	35,339
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 80 FT	21	14,767
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 85 FT	1	0
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 85 FT	1	2,130
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 85 FT	1	2,953
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 85 FT	1	3,438
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 85 FT	1	4,407
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 85 FT	1	4,919
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 85 FT	1	24,333
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 85 FT	2	1,357
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 85 FT	2	3,429

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Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 85 FT	2	4,077
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 85 FT	2	8,077
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 85 FT	2	9,721
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 85 FT	2	17,187
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 85 FT	3	2,504
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 85 FT	3	3,065
E364.00-Poles, Towers, and Fixtures	28-Feb-08	POLE WOOD 85 FT	3	40,532
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 85 FT	4	5,937
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 85 FT	8	49,980
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 90 FT	1	614
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 90 FT	1	749
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 90 FT	1	819
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 90 FT	1	918
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 90 FT	1	2,540
E364.00-Poles, Towers, and Fixtures	28-Feb-08	POLE WOOD 90 FT	1	18,223
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 90 FT	2	942
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 90 FT	5	297
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 90 FT	6	32,158
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 95 FT	1	0
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 95 FT	1	2,538
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 95 FT	1	3,683
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 95 FT	1	16,766
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 95 FT	4	33,989
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 95 FT	5	887
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLES, MOD	1	0
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLES, MOD	1	1,465
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLES, MOD	1	2,553
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLES, MOD	2	1,721
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLES, MOD	2	1,917
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLES, MOD	2	4,558
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLES, MOD	3	3,890
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLES, MOD	3	5,177
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLES, MOD	4	5,310
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLES, MOD	6	8,965
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLES, MOD	6	10,089
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLES, MOD	6	12,084
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLES, MOD	8	7,367
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLES, MOD	12	7,805
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLES, MOD	88	14,948
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLES, MOD	120	20,383
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLES, MOD	184	31,254
E364.00-Poles, Towers, and Fixtures	30-May-06	STEEL POLES	1	0

Louisville Gas and Electric Company
Plant Account 364.00 - Poles Towers and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-92	STEEL POLES	1	8,234
E364.00-Poles, Towers, and Fixtures	1-Jan-97	STEEL POLES	1	13,796
E364.00-Poles, Towers, and Fixtures	1-Jan-79	STEEL POLES	2	2,373
E364.00-Poles, Towers, and Fixtures	1-Jan-65	STEEL POLES	4	1,064
E364.00-Poles, Towers, and Fixtures	1-Jan-42	STEEL POLES	4	3,524
E364.00-Poles, Towers, and Fixtures	1-Jan-86	STEEL POLES	4	5,960
E364.00-Poles, Towers, and Fixtures	1-Jan-93	STEEL POLES	5	42,488
E364.00-Poles, Towers, and Fixtures	1-Jan-57	STEEL POLES	7	866
E364.00-Poles, Towers, and Fixtures	1-Jan-69	STEEL POLES	7	2,435
E364.00-Poles, Towers, and Fixtures	1-Jan-76	STEEL POLES	7	5,574
E364.00-Poles, Towers, and Fixtures	1-Jan-66	STEEL POLES	8	2,409
E364.00-Poles, Towers, and Fixtures	1-Jan-72	STEEL POLES	8	3,748
E364.00-Poles, Towers, and Fixtures	1-Jan-73	STEEL POLES	8	4,244
E364.00-Poles, Towers, and Fixtures	1-Jan-67	STEEL POLES	10	3,144
E364.00-Poles, Towers, and Fixtures	1-Jan-71	STEEL POLES	10	4,245
E364.00-Poles, Towers, and Fixtures	1-Jan-68	STEEL POLES	11	3,672
E364.00-Poles, Towers, and Fixtures	1-Jan-70	STEEL POLES	11	4,438
E364.00-Poles, Towers, and Fixtures	1-Jan-75	STEEL POLES	12	8,196
E364.00-Poles, Towers, and Fixtures	1-Jan-77	STEEL POLES	13	10,787
E364.00-Poles, Towers, and Fixtures	1-Jan-74	STEEL POLES	15	9,249
E364.00-Poles, Towers, and Fixtures	1-Jan-78	STEEL POLES	15	14,652
E364.00-Poles, Towers, and Fixtures	1-Jan-63	STEEL POLES	24	4,347
E364.00-Poles, Towers, and Fixtures	1-Jan-65	TOWERS	1	0
E364.00-Poles, Towers, and Fixtures	1-Jan-35	TOWERS	1	855
E364.00-Poles, Towers, and Fixtures	1-Jan-71	TOWERS	3	1
E364.00-Poles, Towers, and Fixtures	1-Jan-34	TOWERS	3	6,223
E364.00-Poles, Towers, and Fixtures	1-Jan-76	TOWERS	5	4
E364.00-Poles, Towers, and Fixtures	1-Jan-69	TOWERS	6	3
E364.00-Poles, Towers, and Fixtures	1-Jan-75	TOWERS	6	5
E364.00-Poles, Towers, and Fixtures	1-Jan-91	TOWERS	6	6
E364.00-Poles, Towers, and Fixtures	1-Jan-82	TOWERS	6	10
E364.00-Poles, Towers, and Fixtures	1-Jan-88	TOWERS	7	5
E364.00-Poles, Towers, and Fixtures	1-Jan-85	TOWERS	8	8
E364.00-Poles, Towers, and Fixtures	1-Jan-84	TOWERS	8	10
E364.00-Poles, Towers, and Fixtures	1-Jan-90	TOWERS	9	10
E364.00-Poles, Towers, and Fixtures	1-Jan-72	TOWERS	10	5
E364.00-Poles, Towers, and Fixtures	1-Jan-77	TOWERS	10	9
E364.00-Poles, Towers, and Fixtures	1-Jan-67	TOWERS	13	5
E364.00-Poles, Towers, and Fixtures	1-Jan-78	TOWERS	13	14
E364.00-Poles, Towers, and Fixtures	1-Jan-79	TOWERS	13	14
E364.00-Poles, Towers, and Fixtures	1-Jan-57	TOWERS	13	20,143
E364.00-Poles, Towers, and Fixtures	1-Jan-74	TOWERS	15	11

Louisville Gas and Electric Company
Plant Account 364.00 - Poles Towers and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-81	TOWERS	18	26
E364.00-Poles, Towers, and Fixtures	1-Jan-68	TOWERS	21	48,372
E364.00-Poles, Towers, and Fixtures	1-Jan-80	TOWERS	36	43
E364.00-Poles, Towers, and Fixtures	1-Jan-73	TOWERS	52	(75,752)
E364.00-Poles, Towers, and Fixtures	1-Jan-98	TOWERS	190	4,641
E364.00-Poles, Towers, and Fixtures	1-Jan-66	TOWERS	1,186	508
E364.00-Poles, Towers, and Fixtures	1-Jan-70	TOWERS	7,473	(50,789)
E364.00-Poles, Towers, and Fixtures	1-Jan-42	TOWERS	23,985	2,989
Total				$ 119,084,747

Seelye Rebuttal Exhibit 11

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2009-00549

Response to Third Data Request of Commission Staff
Dated March 26, 2010

Question No. 3

Responding Witness: William Steven Seelye

Q-3. Refer to Seelye Exhibit 11, LG&E's response to Item 119 of Commission Staff's Second Data Request ("Staff's Second Request"), and LG&E's response to Item 28 of the Initial Data Request of the Kentucky Cable Telecommunications Association.

a. With regard to the response to Item 119, explain in detail the difference between a levelized and non-levelized charge.

b. Recalculate the CATV attachment charges with the only change being the use of net plant investment costs and provide an updated Exhibit 11.

c. The response to Item 28 discusses the calculation of the operation and maintenance expenses used in the calculation of the CATV charges.

(1) Starting with the rates as calculated in the application, recalculate the CATV rates if tree trimming expenses related to services and overhead conductors is excluded from the calculation of the adder for operation and maintenance expenses. If the expenses related to services and overhead conductors cannot be excluded from account 593004, Tree Trimming of Electric Distribution, recalculate the CATV rates if the adder for operation and maintenance expenses is calculated by dividing the Expenses Assigned to Poles of $6,817,950 by the net book value of Accounts 364, 365, and 369. Include an updated Exhibit 11 in the response.

(2) Starting with the rates as calculated in response to part b. of this request, recalculate the CATV rates if tree trimming expenses related to services and overhead conductors is excluded from the calculation of the adder for operation and maintenance expenses. If the expenses related to services and overhead conductors cannot be excluded from account 593004, Tree Trimming of Electric Distribution, recalculate the CATV rates if the adder for operation and maintenance expenses is calculated by dividing the Expenses Assigned to Poles of $6,817,950 by the net book value of Accounts 364, 365, and 369. Include an updated Exhibit 11 in the response

A-3. a. A *levelized carrying* charge is a uniform series of payments calculated by applying a uniform series capital recovery factor to the gross original cost investment. A capital recovery factor is equal to the rate of return plus sinking fund depreciation. The calculation of a levelized carrying charge rate is identical to the calculation of a conventional mortgage payment on a home. In calculating a levelized carrying charge -- or a mortgage payment -- a capital recovery factor is applied to the original, un-depreciated investment ("gross investment"). Without considering income taxes, a levelized carrying charge (LCC) is therefore calculated by applying the return on investment (ROR) plus the sinking fund depreciation to the gross investment, as follows:

LCC = Gross Investment x [ROR + Sinking Fund Depreciation Rate]

Mathematically, it is not appropriate to apply a capital recovery factor (which is equal to rate of return plus sinking fund depreciation) to the depreciated investment ("net investment"). In the context of the proposed CATV attachment charge, applying a capital recovery factor – which reflects *sinking fund depreciation* as opposed to *straight line depreciation* – to net investment would result in a significant under-recovery of costs and would thus inappropriately shift these costs onto other customers.

A *non-levelized carrying charge* (NLCC) is a non-uniform series of payments calculated by applying the rate of return to net investment and then adding straight-line depreciation, as follows:

NLCC = Net Investment x ROR + Straight Line Depreciation

A non-levelized carrying charge calculation corresponds to the methodology used to determine revenue requirements in a rate case. Importantly, in a rate case *straight line depreciation* rather than *sinking fund depreciation* is used to calculate revenue requirements.

On a present value basis, levelized carrying charges are equivalent to non-levelized carrying charges over the life of the investment. This can be seen in the following attachment (Table I) which compares the present-value non-levelized carrying charges on a $1,000 investment to the present-value levelized carrying charges on the same $1,000 investment. Please note that for both calculations, the sum of present value revenue carrying charges is equal to the original $1,000 investment.

But if sinking fund depreciation rather than straight-line depreciation is applied to net investment then an incorrect result is obtained. As seen in Table II, calculating carrying charges by applying a *sinking fund depreciation* rate to the *net investment* results in significant under-recovery of carrying costs. When the levelized and non-levelized carrying charges are properly calculated, the sum of the present-value carrying charges for each series is equal to $1,000. But when sinking fund depreciation is applied to net investment, the sum of the present value carrying charges is only equal to $721.54. What this means is that if carrying charges are miscalculated in this manner, only 72.15% of cost will be recovered over the life of the investment.

The conclusion reached is that either methodology – either a levelized fixed charge calculation or non-levelized fixed charge calculation – is reasonable assuming that the methodologies are properly applied *and* assuming that the same methodology is consistently applied over time. While on a present value basis both methodologies will yield the same result over the life of the investment, during any particular year the carrying charges will likely be different. For this reason, generally it is not appropriate to switch back and forth between the two methodologies. While LG&E does not have a fundamental objection with using a non-levelized carrying charge calculation to determine the CATV attachment charges *as long as straight-line depreciation is used in the calculation*, the Company does not believe that it is appropriate to switch back and forth between the two methodologies.

The use of levelized versus non-levelized carrying charge rates has been considered extensively by the Federal Energy Regulatory Commission ("FERC"). The FERC will allow the application of a levelized carrying charge rate (with sinking fund depreciation) to gross plant -- which it calls the "levelized gross plant method" -- or the application of a non-levelized carrying charge rate (with straight-line depreciation) to net plant – which it calls "nonlevelized net plant method". The FERC, however, is reluctant to allow a utility to switch back and forth between the two methodologies. In a series of cases involving levelized carrying charges, the FERC rejected attempts to switch from a "net plant" approach to a "levelized" approach in midstream, finding that "allowing Consumers to switch pricing methodologies from the nonlevelized approach ... to the levelized approach ... is inappropriate." *Consumers Energy Co., Opinion No. 429*, 85 FERC ¶ 61,100 at 61,366 (1998), *reh'g granted, Opinion No. 429-A,* 89 FERC ¶ 61,138 (1999), *reh'g denied, Opinion No. 429-B*, 95 FERC ¶ 61,084 (2001); *accord Ky. Utils. Co., Opinion No. 432*, 85 FERC ¶ 61,274 at 62,105 (1998). In the *Opinion 432*, the FERC did not allow Kentucky Utilities Company ("KU") to change methodologies, stating as follows:

> In conclusion, we believe that either a levelized gross plant or a non-levelized rate design can produce comparable, reasonable results if they are used consistently. Here, however, KU proposes

> to switch methods. In supporting such a switch, a utility must prove that its proposed method is reasonable in light of its past recovery of capital costs using a different method. Here, KU has not persuaded us that the switch is appropriate in the circumstances of this case.

Regarding CATV attachment charges, considering the historical practice of calculating the charges using the levelized gross plant methodology, the Company maintains that the historical practice should be continued in the current proceeding.

b. As indicated in response to LG&E KCTA 1-8, the Company does not have information concerning the net plant costs related to the types of poles (35 foot, 40 foot, and 45 foot poles) used to calculate the proposed CATV attachment charge. A *rough estimate* can be developed by applying the ratio of net plant to gross plant for Account 364 – Poles, Towers and Fixtures to the applicable gross plant unit costs for 35, 40, and 45 foot poles. As explained above, using net plant necessitates the application of straight line depreciation rather than sinking fund depreciation. A non-levelized carrying charge calculation using *roughly estimated* net plant data is attached.

c. (1) Expenses related to services and overhead conductors cannot be excluded from account 593004. Attached is a recalculation of Seelye Exhibit 11 with the operation and maintenance expense adder calculated by dividing the Expenses Assigned to Poles by the *net* book value of Accounts 364, 365, and 369. Because the operation and maintenance expense adder is applied to *gross* plant costs in Seelye Exhibit 11, a recalculation of Seelye Exhibit 11 is also attached, with the operation and maintenance expense adder calculated by dividing the Expenses Assigned to Poles by the *gross* book value of Accounts 364, 365, and 369.

(2) Attached is a recalculation of the attachment to the response to sub-part b of this Question, with the operation and maintenance expense adder calculated by dividing the Expenses Assigned to Poles by the *net* book value of Accounts 364, 365, and 369.

Table I

(a)	Book Life	35 Years
(b)	Straight Line Depreciation (1/(a))	2.86%
(c)	Sinking-Fund Depreciation (see formula)	0.54%
(d)	Rate of Return	8.32%
(e)	Capital Recovery Factor (CFR) [(c) + (d)]	8.86%

	Non-Levelized Carrying Charges					Levelized Carrying Charges		
Year (1)	Net Investment (2)	Return (3)	Straight Line Depreciation (4)	Non-Levelized Carrying Charges (5)	Present Value at 8.32% ROR (6)	Gross Investment (7)	Non-Levelized Carrying Charges (8) [(e) x (7)]	Present Value at 8.32% ROR (6)
1	$1,000.00	$83.20	$28.57	$111.77	$103.19	$1,000.00	$88.60	$81.80
2	971.43	80.82	28.57	109.39	93.23	1,000.00	88.60	75.51
3	942.86	78.45	28.57	107.02	84.20	1,000.00	88.60	69.71
4	914.29	76.07	28.57	104.64	76.01	1,000.00	88.60	64.36
5	885.71	73.69	28.57	102.26	68.58	1,000.00	88.60	59.42
6	857.14	71.31	28.57	99.89	61.84	1,000.00	88.60	54.85
7	828.57	68.94	28.57	97.51	55.73	1,000.00	88.60	50.64
8	800.00	66.56	28.57	95.13	50.19	1,000.00	88.60	46.75
9	771.43	64.18	28.57	92.75	45.18	1,000.00	88.60	43.16
10	742.86	61.81	28.57	90.38	40.64	1,000.00	88.60	39.84
11	714.29	59.43	28.57	88.00	36.53	1,000.00	88.60	36.78
12	685.71	57.05	28.57	85.62	32.82	1,000.00	88.60	33.96
13	657.14	54.67	28.57	83.25	29.45	1,000.00	88.60	31.35
14	628.57	52.30	28.57	80.87	26.42	1,000.00	88.60	28.94
15	600.00	49.92	28.57	78.49	23.67	1,000.00	88.60	26.72
16	571.43	47.54	28.57	76.11	21.19	1,000.00	88.60	24.67
17	542.86	45.17	28.57	73.74	18.95	1,000.00	88.60	22.77
18	514.29	42.79	28.57	71.36	16.93	1,000.00	88.60	21.02
19	485.71	40.41	28.57	68.98	15.11	1,000.00	88.60	19.41
20	457.14	38.03	28.57	66.61	13.47	1,000.00	88.60	17.92
21	428.57	35.66	28.57	64.23	11.99	1,000.00	88.60	16.54
22	400.00	33.28	28.57	61.85	10.66	1,000.00	88.60	15.27
23	371.43	30.90	28.57	59.47	9.46	1,000.00	88.60	14.10
24	342.86	28.53	28.57	57.10	8.39	1,000.00	88.60	13.01
25	314.29	26.15	28.57	54.72	7.42	1,000.00	88.60	12.02
26	285.71	23.77	28.57	52.34	6.55	1,000.00	88.60	11.09
27	257.14	21.39	28.57	49.97	5.77	1,000.00	88.60	10.24
28	228.57	19.02	28.57	47.59	5.08	1,000.00	88.60	9.45
29	200.00	16.64	28.57	45.21	4.45	1,000.00	88.60	8.73
30	171.43	14.26	28.57	42.83	3.90	1,000.00	88.60	8.06
31	142.86	11.89	28.57	40.46	3.40	1,000.00	88.60	7.44
32	114.29	9.51	28.57	38.08	2.95	1,000.00	88.60	6.87
33	85.71	7.13	28.57	35.70	2.55	1,000.00	88.60	6.34
34	57.14	4.75	28.57	33.33	2.20	1,000.00	88.60	5.85
35	28.57	2.38	28.57	30.95	1.89	1,000.00	88.60	5.40
Sum of Present Value Carrying Charges					$1,000.00			$1,000.00

Table II

(a)	Book Life	35 Years
(b)	Straight Line Depreciation (1/(a))	2.86%
(c)	Sinking-Fund Depreciation (see formula)	0.54%
(d)	Rate of Return	8.32%
(e)	Capital Recovery Factor (CFR) [(c) + (d)]	8.86%

	Non-Levelized Carrying Charges					*Misapplied* Levelized Carrying Charges		
Year (1)	Net Investment (2)	Return (3)	Straight Line Depreciation (4)	Non-Levelized Carrying Charges (5)	Present Value at 8.32% ROR (6)	Net Investment (7)	Non-Levelized Carrying Charges (8)	Present Value at 8.32% ROR (6)
							[(e) x (7)]	
1	$1,000.00	$83.20	$28.57	$111.77	$103.19	$1,000.00	$88.60	$81.80
2	971.43	80.82	28.57	109.39	93.23	971.43	86.07	73.36
3	942.86	78.45	28.57	107.02	84.20	942.86	83.54	65.73
4	914.29	76.07	28.57	104.64	76.01	914.29	81.01	58.84
5	885.71	73.69	28.57	102.26	68.58	885.71	78.48	52.63
6	857.14	71.31	28.57	99.89	61.84	857.14	75.95	47.02
7	828.57	68.94	28.57	97.51	55.73	828.57	73.41	41.96
8	800.00	66.56	28.57	95.13	50.19	800.00	70.88	37.40
9	771.43	64.18	28.57	92.75	45.18	771.43	68.35	33.29
10	742.86	61.81	28.57	90.38	40.64	742.86	65.82	29.60
11	714.29	59.43	28.57	88.00	36.53	714.29	63.29	26.27
12	685.71	57.05	28.57	85.62	32.82	685.71	60.76	23.29
13	657.14	54.67	28.57	83.25	29.45	657.14	58.22	20.60
14	628.57	52.30	28.57	80.87	26.42	628.57	55.69	18.19
15	600.00	49.92	28.57	78.49	23.67	600.00	53.16	16.03
16	571.43	47.54	28.57	76.11	21.19	571.43	50.63	14.10
17	542.86	45.17	28.57	73.74	18.95	542.86	48.10	12.36
18	514.29	42.79	28.57	71.36	16.93	514.29	45.57	10.81
19	485.71	40.41	28.57	68.98	15.11	485.71	43.04	9.43
20	457.14	38.03	28.57	66.61	13.47	457.14	40.50	8.19
21	428.57	35.66	28.57	64.23	11.99	428.57	37.97	7.09
22	400.00	33.28	28.57	61.85	10.66	400.00	35.44	6.11
23	371.43	30.90	28.57	59.47	9.46	371.43	32.91	5.24
24	342.86	28.53	28.57	57.10	8.39	342.86	30.38	4.46
25	314.29	26.15	28.57	54.72	7.42	314.29	27.85	3.78
26	285.71	23.77	28.57	52.34	6.55	285.71	25.32	3.17
27	257.14	21.39	28.57	49.97	5.77	257.14	22.78	2.63
28	228.57	19.02	28.57	47.59	5.08	228.57	20.25	2.16
29	200.00	16.64	28.57	45.21	4.45	200.00	17.72	1.75
30	171.43	14.26	28.57	42.83	3.90	171.43	15.19	1.38
31	142.86	11.89	28.57	40.46	3.40	142.86	12.66	1.06
32	114.29	9.51	28.57	38.08	2.95	114.29	10.13	0.78
33	85.71	7.13	28.57	35.70	2.55	85.71	7.59	0.54
34	57.14	4.75	28.57	33.33	2.20	57.14	5.06	0.33
35	28.57	2.38	28.57	30.95	1.89	28.57	2.53	0.15
Sum of Present Value Carrying Charges					$1,000.00			$721.54

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Gross Installed Cost	Gross Average Installed Cost	Net / Gross Factor for Account 364	Estimate of Net Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2009					
35'	21,992	$ 9,895,841	$ 449.97	0.4413117	$ 198.58
40'	61,023	25,998,372	426.04	0.4413117	188.02
	83,015	$ 35,894,213	$ 432.38		190.82
Three-User Poles					
40'	61,023	$ 25,998,372	$ 426.04	0.4413117	$ 188.02
45'	22,136	23,008,391	1,039.41	0.4413117	458.70
	83,159	$ 49,006,763	$ 589.31		260.07

	Number of Attachments	Weighted Cost
Two-User Pole Charge		
$190.82 x .1224 Usage Space Factor = $ 23.36 $ 23.36 x .2075 Annual Carrying Charge = $ 4.85	17,699	$ 85,774
Three-User Pole Charge		
$260.07 x .0759 Usage Space Factor = $19.74 $ 19.74 x .2075 Annual Carrying Charge = $4.10	68,646	$ 281,162
Weighted Total	86,345	$ 366,937
Weighted Average Monthly Cost		$ 4.25

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	8.32%
Depreciation - Straight Line	2.86%
Income Tax (1)	3.63%
Property Tax and Insurance	0.22%
Operation and Maintenance (Page 3)	5.73%
Total	20.75%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Common	53.86%	11.50%	6.19%
Preferred	0.00%	0.00%	0.00%
Total Equity	53.86%		6.19%
Debt	46.14%	4.61%	2.13%
Total Capitalization	100.00%		8.32%

Composite Federal and State Income Taxes rate = 36.93%

Income Tax = (0.3693/(1-0.3693) x 0.0619 = 3.63%

LOUISVILLE GAS AND ELECTRIC COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2009

(1) Labor Charged to 592 - Poles, Towers and Fixtures Subaccount	$ 289,969	
- Tree Trimming	225,900	
		$ 515,870
Total Labor		$ 56,166,593
Total Administrative and General Expenses		$ 73,557,685

<u>Assignment of a Portion of A & G Expenses to Poles</u>

($515,870/$56,166,593) x $73,557,685 = $675,600

<u>Expenses Assigned to Poles</u>

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 1,366,766
Tree Trimming of Electric Distribution Routes 593004	4,775,583
A & G Expenses Assigned to Poles	675,600
Total	$ 6,817,950

<u>Adder to Annual Carrying Charges for O & M Expenses</u>

$ 6,817,950	Expenses Assigned to Poles	=	5.73%
119,084,747	Plant in Service - Account 364		

<u>Net Plant to Gross Plant Ratio for Account 364</u>

Gross Plant	Depreciation	Net Plant	Net to Gross Ratio
$ 119,084,747	$ 66,531,254	$ 52,553,493	44.131%

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Gross Installed Cost	Gross Average Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2009			
35'	21,992	$ 9,895,841	$ 449.97
40'	61,023	25,998,372	426.04
	83,015	$ 35,894,213	$ 432.38
Three-User Poles			
40'	61,023	$ 25,998,372	$ 426.04
45'	22,136	23,008,391	1,039.41
	83,159	$ 49,006,763	$ 589.31

	Number of Attachments	Weighted Cost
Two-User Pole Charge		
$432.38 x .1224 Usage Space Factor = $ 52.92 $ 52.92 x .1465 Annual Carrying Charge = $ 7.75	17,699	$ 137,222
Three-User Pole Charge		
$589.31 x .0759 Usage Space Factor = $44.73 $ 44.73 x .1465 Annual Carrying Charge = $6.55	68,646	$ 449,804
Weighted Total	86,345	$ 587,026
Weighted Average Monthly Cost		$ 6.80

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	8.32%
Depreciation - Sinking Fund	0.54%
Income Tax (1)	3.63%
Property Tax and Insurance	0.22%
Operation and Maintenance (Page 3)	1.94%
Total	14.65%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Common	53.86%	11.50%	6.19%
Preferred	0.00%	0.00%	0.00%
Total Equity	53.86%		6.19%
Debt	46.14%	4.61%	2.13%
Total Capitalization	100.00%		8.32%

Composite Federal and State Income Taxes rate = 36.93%

Income Tax = (0.3693/(1-0.3693) x 0.0619 = 3.63%

LOUISVILLE GAS AND ELECTRIC COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2009

(1) Labor Charged to 592 - Poles, Towers and Fixtures Subaccount	$ 289,969	
- Tree Trimming	225,900	
		$ 515,870
Total Labor		$ 56,166,593
Total Administrative and General Expenses		$ 73,557,685

Assignment of a Portion of A & G Expenses to Poles

($515,870/$56,166,593) x $73,557,685 = $675,600

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 1,366,766
Tree Trimming of Electric Distribution Routes 593004	4,775,583
A & G Expenses Assigned to Poles	675,600
Total	$ 6,817,950

Adder to Annual Carrying Charges for O & M Expenses

$ 6,817,950	Expenses Assigned to Poles	=	1.94%
351,061,565	Plant in Service - 364 , 365, and 369		

Net Plant to Gross Plant Ratio for Accounts 364,365 and 369

Gross Plant	Depreciation	Net Plant	Net to Gross Ratio
$ 351,061,565	$ 173,586,068	$ 177,475,497	50.554%

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Gross Installed Cost	Gross Average Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2009			
35'	21,992	$ 9,895,841	$ 449.97
40'	61,023	25,998,372	426.04
	83,015	$ 35,894,213	$ 432.38
Three-User Poles			
40'	61,023	$ 25,998,372	$ 426.04
45'	22,136	23,008,391	1,039.41
	83,159	$ 49,006,763	$ 589.31

	Number of Attachments	Weighted Cost
Two-User Pole Charge		
$432.38 x .1224 Usage Space Factor = $ 52.92 $ 52.92 x .1655 Annual Carrying Charge = $ 8.76	17,699	$ 155,015
Three-User Pole Charge		
$589.31 x .0759 Usage Space Factor = $44.73 $ 44.73 x .1655 Annual Carrying Charge = $7.40	68,646	$ 508,129
Weighted Total	86,345	$ 663,144
Weighted Average Monthly Cost		$ 7.68

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	8.32%
Depreciation - Sinking Fund	0.54%
Income Tax (1)	3.63%
Property Tax and Insurance	0.22%
Operation and Maintenance (Page 3)	3.84%
Total	16.55%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Common	53.86%	11.50%	6.19%
Preferred	0.00%	0.00%	0.00%
Total Equity	53.86%		6.19%
Debt	46.14%	4.61%	2.13%
Total Capitalization	100.00%		8.32%

Composite Federal and State Income Taxes rate = 36.93%

Income Tax = (0.3693/(1-0.3693) x 0.0619 = 3.63%

LOUISVILLE GAS AND ELECTRIC COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2009

(1) Labor Charged to 592 - Poles, Towers and Fixtures Subaccount	$ 289,969	
- Tree Trimming	225,900	
		$ 515,870
Total Labor		$ 56,166,593
Total Administrative and General Expenses		$ 73,557,685

Assignment of a Portion of A & G Expenses to Poles

($515,870/$56,166,593) x $73,557,685 = $675,600

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 1,366,766
Tree Trimming of Electric Distribution Routes 593004	4,775,583
A & G Expenses Assigned to Poles	675,600
Total	$ 6,817,950

Adder to Annual Carrying Charges for O & M Expenses

$ 6,817,950	Expenses Assigned to Poles	=	3.84%
177,475,497	Plant in Service - 364 , 365, and 369		

Net Plant to Gross Plant Ratio for Accounts 364,365 and 369

Gross Plant	Depreciation	Net Plant	Net to Gross Ratio
$ 351,061,565	$ 173,586,068	$ 177,475,497	50.554%

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Gross Installed Cost	Gross Average Installed Cost	Net Gross Factor for Account 364	Estimate of Net Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2009					
35'	21,992	$ 9,895,841	$ 449.97	0.50554	$ 227.48
40'	61,023	25,998,372	426.04	0.50554	215.38
	83,015	$ 35,894,213	$ 432.38		218.59
Three-User Poles					
40'	61,023	$ 25,998,372	$ 426.04	0.50554	$ 215.38
45'	22,136	23,008,391	1,039.41	0.50554	525.46
	83,159	$ 49,006,763	$ 589.31		297.92

	Number of Attachments	Weighted Cost
Two-User Pole Charge		
$218.59 x .1224 Usage Space Factor = $ 26.75 $ 26.75 x .1887 Annual Carrying Charge = $ 5.05	17,699	$ 89,338
Three-User Pole Charge		
$297.92 x .0759 Usage Space Factor = $22.61 $ 22.61 x .1887 Annual Carrying Charge = $4.27	68,646	$ 292,844
Weighted Total	86,345	$ 382,181
Weighted Average Monthly Cost		$ 4.43

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	8.32%
Depreciation - Straight Line	2.86%
Income Tax (1)	3.63%
Property Tax and Insurance	0.22%
Operation and Maintenance (Page 3)	3.84%
Total	18.87%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Common	53.86%	11.50%	6.19%
Preferred	0.00%	0.00%	0.00%
Total Equity	53.86%		6.19%
Debt	46.14%	4.61%	2.13%
Total Capitalization	100.00%		8.32%

Composite Federal and State Income Taxes rate = 36.93%

Income Tax = (0.3693/(1-0.3693) x 0.0619 = 3.63%

LOUISVILLE GAS AND ELECTRIC COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2009

(1) Labor Charged to 592 - Poles, Towers and Fixtures Subaccount	$ 289,969	
- Tree Trimming	225,900	
		$ 515,870
Total Labor		$ 56,166,593
Total Administrative and General Expenses		$ 73,557,685

Assignment of a Portion of A & G Expenses to Poles

($515,870/$56,166,593) x $73,557,685 = $675,600

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 1,366,766
Tree Trimming of Electric Distribution Routes 593004	4,775,583
A & G Expenses Assigned to Poles	675,600
Total	$ 6,817,950

Adder to Annual Carrying Charges for O & M Expenses

$ 6,817,950	Expenses Assigned to Poles	=	3.84%
177,475,497	Plant in Service - 364 , 365, and 369		

Net Plant to Gross Plant Ratio for Accounts 364,365 and 369

Gross Plant	Depreciation	Net Plant	Net to Gross Ratio
$ 351,061,565	$ 173,586,068	$ 177,475,497	50.554%

Seelye Rebuttal Exhibit 12

(a)	Book Life	35 Years
(b)	Straight Line Depreciation (1/(a))	2.86%
(c)	Sinking-Fund Depreciation (see formula)	0.54%
(d)	Rate of Return	8.32%
(e)	Capital Recovery Factor (CFR) [(c) + (d)]	8.86%

	Non-Levelized Carrying Charges					Levelized Carrying Charges			Ms. Kravtin's Inconsistent Approach		
Year (1)	Net Investment (2)	Return (3)	Straight Line Depreciation (4)	Non-Levelized Carrying Charges (5)	Present Value at 8.32% ROR (6)	Gross Investment (7)	Levelized Carrying Charges (8)	Present Value at 8.32% ROR (9)	Choosing the Charge that Results in the Lowest Rate (10)	Difference From Consistently Applied Levelized Approach (11)	Present Value Difference at 8.32% ROR
							[(e) x (7)]			(10) - (8)	
1	$1,000.00	$83.20	$28.57	$111.77	$103.19	$1,000.00	$88.60	$81.80	$88.60	$0.00	$81.80
2	971.43	80.82	28.57	109.39	93.23	1,000.00	88.60	75.51	$88.60	$0.00	$75.51
3	942.86	78.45	28.57	107.02	84.20	1,000.00	88.60	69.71	$88.60	$0.00	$69.71
4	914.29	76.07	28.57	104.64	76.01	1,000.00	88.60	64.36	$88.60	$0.00	$64.36
5	885.71	73.69	28.57	102.26	68.58	1,000.00	88.60	59.42	$88.60	$0.00	$59.42
6	857.14	71.31	28.57	99.89	61.84	1,000.00	88.60	54.85	$88.60	$0.00	$54.85
7	828.57	68.94	28.57	97.51	55.73	1,000.00	88.60	50.64	$88.60	$0.00	$50.64
8	800.00	66.56	28.57	95.13	50.19	1,000.00	88.60	46.75	$88.60	$0.00	$46.75
9	771.43	64.18	28.57	92.75	45.18	1,000.00	88.60	43.16	$88.60	$0.00	$43.16
10	742.86	61.81	28.57	90.38	40.64	1,000.00	88.60	39.84	$88.60	$0.00	$39.84
11	714.29	59.43	28.57	88.00	36.53	1,000.00	88.60	36.78	$88.00	($0.60)	$36.53
12	685.71	57.05	28.57	85.62	32.82	1,000.00	88.60	33.96	$85.62	($2.98)	$32.82
13	657.14	54.67	28.57	83.25	29.45	1,000.00	88.60	31.35	$83.25	($5.36)	$29.45
14	628.57	52.30	28.57	80.87	26.42	1,000.00	88.60	28.94	$80.87	($7.73)	$26.42
15	600.00	49.92	28.57	78.49	23.67	1,000.00	88.60	26.72	$78.49	($10.11)	$23.67
16	571.43	47.54	28.57	76.11	21.19	1,000.00	88.60	24.67	$76.11	($12.49)	$21.19
17	542.86	45.17	28.57	73.74	18.95	1,000.00	88.60	22.77	$73.74	($14.87)	$18.95
18	514.29	42.79	28.57	71.36	16.93	1,000.00	88.60	21.02	$71.36	($17.24)	$16.93
19	485.71	40.41	28.57	68.98	15.11	1,000.00	88.60	19.41	$68.98	($19.62)	$15.11
20	457.14	38.03	28.57	66.61	13.47	1,000.00	88.60	17.92	$66.61	($22.00)	$13.47
21	428.57	35.66	28.57	64.23	11.99	1,000.00	88.60	16.54	$64.23	($24.37)	$11.99
22	400.00	33.28	28.57	61.85	10.66	1,000.00	88.60	15.27	$61.85	($26.75)	$10.66
23	371.43	30.90	28.57	59.47	9.46	1,000.00	88.60	14.10	$59.47	($29.13)	$9.46
24	342.86	28.53	28.57	57.10	8.39	1,000.00	88.60	13.01	$57.10	($31.51)	$8.39
25	314.29	26.15	28.57	54.72	7.42	1,000.00	88.60	12.02	$54.72	($33.88)	$7.42
26	285.71	23.77	28.57	52.34	6.55	1,000.00	88.60	11.09	$52.34	($36.26)	$6.55
27	257.14	21.39	28.57	49.97	5.77	1,000.00	88.60	10.24	$49.97	($38.64)	$5.77
28	228.57	19.02	28.57	47.59	5.08	1,000.00	88.60	9.45	$47.59	($41.01)	$5.08
29	200.00	16.64	28.57	45.21	4.45	1,000.00	88.60	8.73	$45.21	($43.39)	$4.45
30	171.43	14.26	28.57	42.83	3.90	1,000.00	88.60	8.06	$42.83	($45.77)	$3.90
31	142.86	11.89	28.57	40.46	3.40	1,000.00	88.60	7.44	$40.46	($48.15)	$3.40
32	114.29	9.51	28.57	38.08	2.95	1,000.00	88.60	6.87	$38.08	($50.52)	$2.95
33	85.71	7.13	28.57	35.70	2.55	1,000.00	88.60	6.34	$35.70	($52.90)	$2.55
34	57.14	4.75	28.57	33.33	2.20	1,000.00	88.60	5.85	$33.33	($55.28)	$2.20
35	28.57	2.38	28.57	30.95	1.89	1,000.00	88.60	5.40	$30.95	($57.65)	$1.89
Sum of Present Value Carrying Charges					$1,000.00			$1,000.00			$907.26

Seelye Rebuttal Exhibit 13

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity		Installed Cost		Average Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2009					
35'	22,008	$	9,882,811	$	449.06
40'	61,101		25,990,673		425.37
	83,109	$	35,873,484	$	431.64
Three-User Poles					
40'	61,101	$	25,990,673	$	425.37
45'	22,054		22,752,748		1,031.68
	83,155	$	48,743,421	$	586.18

	Number of Attachments		Weighted Cost
Two-User Pole Charge			
\$431.64 x .1224 Usage Space Factor = \$ 52.83			
\$ 52.83 x .1625 Annual Carrying Charge = \$ 8.58	17,699	$	151,943
Three-User Pole Charge			
\$586.18 x .0759 Usage Space Factor = \$44.49			
\$ 44.49 x .1625 Annual Carrying Charge = \$7.23	68,646	$	496,254
Weighted Total	86,345	$	648,197
Weighted Average Monthly Cost		$	7.51

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	8.32%
Depreciation - Sinking Fund	0.54%
Income Tax (1)	3.67%
Property Tax and Insurance	0.22%
Operation and Maintenance (Page 3)	3.50%
Total	16.25%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Common	53.86%	11.50%	6.19%
Preferred	0.00%	0.00%	0.00%
Total Equity	53.86%		6.19%
Debt	46.14%	4.61%	2.13%
Total Capitalization	100.00%		8.32%

Composite Federal and State Income Taxes rate = 37.19%

Income Tax = (0.3719/(1-0.3719) x 0.0619 = 3.67%

LOUISVILLE GAS AND ELECTRIC COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2009

(1) Labor Charged to 593 - Poles, Towers and Fixtures Subaccount	$ 289,969	
- Tree Trimming	225,900	
		$ 515,870
Total Labor		$ 56,166,593
Total Administrative and General Expenses		$ 73,557,685

Assignment of a Portion of A & G Expenses to Poles

($515,870/$56,166,593) x $73,557,685 = $675,600

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 635,609
Tree Trimming of Electric Distribution Routes 593004	2,856,770
A & G Expenses Assigned to Poles	675,600
Total	$ 4,167,980

Adder to Annual Carrying Charges for O & M Expenses

$ 4,167,980	Expenses Assigned to Poles	=	3.50%
119,084,747	Plant in Service - Account 364		