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PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

In the Matter of:

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

REBUTTAL TESTIMONY OF WILLIAM STEVEN SEELYE

PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

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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, 6435 West Highway 146, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility marketing, regulatory analysis, cost of service, rate design and fuel and power procurement.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively referred to as the "Companies").

Q. Did you submit direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut direct testimony presented by various intervenor witnesses on a number of revenue requirement issues, LG&E and KU's cost of service studies, and on the Companies' proposed gas and electric rates.

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Revenue Requirement Issues and Pro-forma Adjustments, (III) Electric Cost of Service, (IV) Allocation of the Electric Rate Increase, (V) Electric Rate Design, (VI) Curtailable Service Rider ("CSR"), (VII) Redundant Capacity Rider, (VIII) Non-Conforming Load, (IX) Gas

Cost of Service Study, (X) Allocation of the Gas Rate Increase, (XI) Gas Rate Design, (XII) Miscellaneous Service Charges, and (XIII) Conclusion.

II. Revenue Requirement Issues and Pro-Forma Adjustments

(a) Regulatory Policy Considerations

Q. Several intervenor witnesses in these proceedings make recommendations that would reduce the Companies' requested rate increases. Do you have any general comments concerning their recommendations and how these recommendations should be evaluated by the Commission?

A. Yes. My overall assessment of the intervenor positions is that too many of their recommendations in this proceeding are driven more by a desire to reduce the Companies' revenue requirements rather than to follow sound regulatory principles and established Commission practices. This is unfortunate. There is a serious danger in parties promoting a results-oriented approach to regulation that is concerned more with immediate outcomes than with promoting a regulatory environment that is based on sound regulatory principles; that is consistent over time; that considers long-term rather than short-term consequences of policy changes; that relies on sound precedents and prior Commission practice rather than developing *ad hoc* policies that promote immediate purposes.

In my rebuttal testimony, I will address several positions taken by intervenor witnesses that are results-oriented rather than grounded in sound regulatory principles and consistent with prior Commission practice. The positions taken by KIUC witness Lane Kollen, Department of Defense witness Thomas J. Prisco, and Attorney General witness

Robert J. Henkes regarding unbilled revenues are results-oriented, fail to follow prior Commission practice, and are incompatible with sound regulatory principles. Mr. Henkes's position regarding the use of rate base versus capitalization is unabashedly results oriented. Although this issue does not affect the outcome in the case, the principle that he outlines – namely, that the Commission should select either rate base or capitalization for use in setting rates depending on whichever results in the lowest revenue requirements – illustrates his results-oriented approach to regulation that relies more on empty rhetoric than on principle. Likewise, Mr. Henkes ignores past Commission practice and his own prior recommendations when he proposes expense adjustments computed by applying an operating ratio to every revenue adjustment proposed by LG&E, even though there is no reasonable basis for making such expense adjustments. Because he does not like the results he sees with the LG&E's year-end adjustments, he offers a brand-new methodology based on projected trends and abandons an approach that has been accepted and prescribed by the Commission for many years. Similarly, the unsound weather normalization adjustment proposed for KU by Attorney General witness Michael J. Majoros is results-oriented at its core and ignores principles and guidelines articulated in prior Commission orders.

Q. What is the danger of intervenor witnesses ignoring past Commission practice and making results-oriented recommendations?

A. In developing revenue requirements in rate cases, the Companies carefully consider and closely follow prior Commission practice as well as guidance provided in previous orders. It is extremely important for utilities to have a high degree of certainty in how revenue requirements will be determined in rate cases. If all parties, including the Companies, chose to ignore sound regulatory principles, prior Commission practice, and previous Commission orders, then rate cases would become free-for-alls with utilities or consumers having little assurance about the methodologies that might be used in future proceedings to determine revenue requirements. In my view, recommendations that are outside the bounds of reasonableness are counterproductive and ultimately detrimental to the ratemaking process.

Q. Do ratepayers and utilities benefit from sound regulation that is consistently applied?

A. Absolutely. I have been involved in the ratemaking process in Kentucky for over 25 years either as a utility employee or a rate consultant. As a consultant working in Kentucky and in many other jurisdictions for almost eight years now, I have formed the opinion that one of the principal reasons that utilities in Kentucky have low rates is that the regulatory environment here has generally been based on sound regulatory principles, slow to depart from established practices, and favorably disposed toward promoting the financial integrity of utilities. Although strong utility management and the proximity to low-cost coal cannot be ignored, I do not feel that these attributes alone can fully explain the rate levels in Kentucky. There are other well managed utilities located near low-cost coal fields that do not have electric rates nearly as low as they are in Kentucky. Furthermore, it is not only the electric rates that are low. LG&E, for instance, has low natural gas rates even though its source of supply is nowhere near Kentucky. Comparing what I have seen in other jurisdictions, Kentucky regulators have successfully adhered to several principles that have helped keep rates down over the long haul. In my opinion, those principles include: (1) not taking every opportunity to defer costs into the future,[1] (2) closely following prior Commission practice and precedent, (3) providing utilities with an opportunity to earn a fair, just and reasonable return, one that is sufficient to attract investor capital, and (4) carefully considering long-term rather than short-term consequences of regulatory policies.

(b) Rate Base vs. Capitalization

Q. Does Mr. Henkes address whether rate base or capitalization should be used to determine revenue requirements?

A. Yes. The revenue requirements for a utility include (i) depreciation and amortization expenses, (ii) operation and maintenance expenses, (iii) income and other taxes, and (iv) a fair, just and reasonable return on investment. For LG&E, the return component of revenue requirements has traditionally been computed on the basis of a return on capitalization, rather than a return on rate base. In most other jurisdictions, the return is computed on the basis of rate base. In my opinion, the Commission should establish a standard valuation methodology and consistently utilize that methodology in rate cases, rather than simply follow whichever approach produces the lowest rates in a given case. Mr. Henkes, though, has an altogether different view:

> *I believe a utility's return requirement for rate making purposes should be determined by applying the calculated overall rate of return to the lower of the utility's capitalization or original cost rate base.* When a utility's capitalization dollar balance is higher than the used and useful rate base investment balance, this *generally indicates* that a portion of this utility's capitalization has been used to finance

1 An example of this is the Commission's practice of allowing utilities to earn a current return on Construction Work in Progress ("CWIP"). By not deferring carrying costs into the future, utility rates are lower now than they would be otherwise.

> investments that are not used and useful to the ratepayers and are therefore not included in the utility's rate base, e.g., non-regulated/non-utility assets, "below-the-line" assets, etc. When a utility's rate base is higher than the capitalization balance, <u>*this could mean*</u> that portions of the rate base investments have been financed with funds other than investor-supplied debt, preferred stock and common equity; or <u>*it could mean*</u> that rate base investments that have been assumed to exist by way of hypothetical formulas (e.g., the "1/8th method" used to estimate assumed cash working capital) do not actually exist. (Direct testimony of Robert J. Henkes, page 13. Emphasis supplied.)

Mr. Henkes uses a lot of qualifying expressions – "generally indicates", "this could mean", "it could mean" – to support his unqualified assertion that the utility should always be penalized through the use of the lower of either rate base or capitalization. While Mr. Henkes only provides examples that support his argument of using the lower of capitalization or rate base, there are any number of circumstances that cause the two not to be equal. During the many years that I have been working in the industry, I have never seen an instance where rate base exactly equaled capitalization. Contrary to Mr. Henkes's claim, total capitalization may be higher than rate base even though the utility has never financed items that are not used and useful. For instance, how do we know, as Mr. Henkes claims, that the 1/8th rule, or a lead-lag study for that matter, does not understate a utility's cash requirements? The 1/8th rule and lead-lag studies simply provide an estimate of the amount of *working* cash necessary to account for timing differences between when expenses are paid and revenues are received. A strong case can be made that utilities need a certain amount of cash *on hand* (instead of merely cash that is *working*) in order to operate the business, an amount that is not accounted for in the computation of cash working capital.

In other proceedings, depending on what he was trying to accomplish, Mr. Henkes has taken an altogether different position on the use of rate base versus capitalization. For instance in Delta Natural Gas Company's last general rate case, Mr. Henkes made the unqualified recommendation that the return should be determined by applying the overall rate of return to rate base, instead of total capitalization. In the Delta Natural Gas proceeding he offered the following testimony:

> Generally, a utility's return requirement is determined by applying the calculated overall rate of return to the rate base investment, not to the capital structure amount. This is because it is rate base that included the investment determined to be used and useful in serving ratepayers. (Direct Testimony of Robert J. Henkes, Delta Natural Gas Company, Case No. 99-176, p. 10.)

In LG&E's last gas base rate case (Case No. 2000-080), Mr. Henkes completely reversed his position and argued for the use of total capitalization instead of rate base. We now see that Mr. Henkes is apparently tired of changing directions and has developed a regulatory philosophy that permits him the flexibility to choose whatever position suits his purposes.

In the current proceeding, the selection of rate base versus capitalization is not an issue, because, consistent with past Commission practice, the Company's proposed rate increase was based on capitalization rather than rate base, and the use of capitalization results in a lower rate increase. Although there is no need to dwell on the issue, it is important to point out that Mr. Henkes's comments illustrate his preference for a results-oriented approach to regulation and a general disdain for sound regulatory principles and prior Commission practice.

(c) Unbilled Revenues

Q. Witnesses Henkes, Kollen, and Prisco make an assortment of recommendations regarding unbilled revenues. What are unbilled revenues?

A. Unbilled revenues represent the estimated revenues resulting from 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 a rough estimate of the Mcf or kWh sales that are unbilled. The unbilled Mcf or kWh 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 kWh 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 kWH?

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 component (ECR), the merger surcredit component, value-delivery component (VDT), earnings sharing mechanism component (ESM), and demand-side management component (DSM), as applicable. The price used to estimate the unbilled revenues is thus an all-in price.

Q. Do LG&E and KU compute unbilled revenues or unbilled Mcf/kWh sales by rate class?

A. No. Unbilled revenues and unbilled Mcf or kWh are not estimated for each rate class. The unbilled Mcf and kWh 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. Do the Companies' compute unbilled demand units (Mcf/day or kW) for rate classes that have demand charges?

A. No. Several of the Companies' electric rate schedules and all of their electric special contracts include demand charges. Also, 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 kWh. It is not refined enough to develop unbilled demand units.

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 month. Second, the unbilled revenue amount recorded in the previous month is subtracted from the actual billed revenues for the month. Since the as-billed revenues for the current month include the unbilled revenues that were recorded in the prior month, this amount must 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:

LOUISVILLE GAS AND ELECTRIC COMPANY UNBILLED GAS REVENUES FOR THE 12 MONTHS ENDED SEPTEMBER 2003			
MONTH	**UNBILLED REVENUE FOR CURRENT MONTH**	**UNBILLED REVENUE FOR PREVIOUS MONTH**	**NET UNBILLED REVENUES**
October 2002	$ 9,932,000	**[$ 3,546,000]**	$ 6,386,000
November	$ 21,507,000	[$ 9,932,000]	$11,575,000
December	$ 21,087,000	[$ 21,507,000]	($ 420,000)
January 2003	$ 31,532,000	[$ 21,087,000]	$10,445,000
February	$ 23,434,000	[$ 31,532,000]	($ 8,098,000)
March	$ 8,776,000	[$ 23,434,000]	($14,658,000)
April	$ 6,250,000	[$ 8,776,000]	($ 2,526,000)
May	$ 4,734,000	[$ 6,250,000]	($ 1,516,000)
June	$ 3,975,000	[$ 4,734,000]	($ 756,000)
July	$ 4,011,000	[$ 3,975,000]	$ 36,000
August	$ 4,693,000	[$ 4,011,000]	$ 682,000
September	**$ 6,326,000**	[$ 4,693,000]	$ 1,633,000
Total Test-Year			**$ 2,780,000**

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, $2,780,000, equals the recorded unbilled revenues for September 2003, the last month of the test year, or $6,326,000, minus the unbilled revenues recorded for

September 2002, the month prior to the beginning of the test year, or $3,546,000 (i.e., $6,326,000 – 3,546,000 = $2,780,000). Consequently, for the twelve-month period, only two entries actually come into play in determining the unbilled revenues – the unbilled revenues for September 2003 that are *added* during the last month and the unbilled revenues for September 2002 that are *subtracted* during the first month.

The following table shows the unbilled entries for LG&E's electric operations during the test year:

LOUISVILLE GAS AND ELECTRIC COMPANY
UNBILLED ELECTRIC REVENUES
FOR THE 12 MONTHS ENDED SEPTEMBER 2003

MONTH	UNBILLED REVENUE FOR CURRENT MONTH	UNBILLED REVENUE FOR PREVIOUS MONTH	NET UNBILLED REVENUES
October 2002	$ 20,328,000	**[$ 21,028,000]**	($ 700,000)
November	$ 20,474,000	[$ 20,328,000]	$ 146,000
December	$ 18,965,000	[$ 20,474,000]	($ 1,509,000)
January 2003	$ 20,054,000	[$ 18,965,000]	$ 1,089,000
February	$ 17,017,000	[$ 20,054,000]	($ 3,037,000)
March	$ 16,415,000	[$ 17,017,000]	($ 602,000)
April	$ 17,466,000	[$ 16,415,000]	$ 1,051,000
May	$ 22,541,000	[$ 17,466,000]	$ 5,075,000
June	$ 25,267,000	[$ 22,541,000]	$ 2,726,000
July	$ 28,780,000	[$ 25,267,000]	$ 3,513,000
August	$ 33,645,000	[$ 28,780,000]	$ 4,865,000
September	**$ 22,895,000**	[$ 33,645,000]	($10,750,000)
Total Test-Year			**$ 1,867,000**

Electric unbilled revenues for the test year, $1,867,000, equals the recorded unbilled revenues for September 2003, the last month of the test year, or $22,895,000, minus the unbilled revenues recorded for September 2002, the month prior to the beginning of the test year, or $21,028,000 (i.e., $22,895,000 – $21,028,000 = $1,867,000).

The following table shows the unbilled entries for KU during the test year:

KENTUCKY UTILITIES COMPANY UNBILLED ELECTRIC REVENUES FOR THE 12 MONTHS ENDED SEPTEMBER 2003			
MONTH	**UNBILLED REVENUE FOR CURRENT MONTH**	**UNBILLED REVENUE FOR PREVIOUS MONTH**	**NET UNBILLED REVENUES**
October 2002	$ 29,594,000	**[$ 29,493,000]**	$ 101,000
November	$ 34,338,000	[$ 29,594,000]	$ 4,744,000
December	$ 33,988,000	[$ 34,338,000]	$ (350,000)
January 2003	$ 35,800,000	[$ 33,988,000]	$ 1,812,000
February	$ 27,116,000	[$ 35,800,000]	$ (8,684,000)
March	$ 24,739,000	[$ 27,116,000]	$ (2,377,000)
April	$ 24,384,000	[$ 24,739,000]	$ (355,000)
May	$ 26,408,000	[$ 24,384,000]	$ 2,024,000
June	$ 28,748,000	[$ 26,408,000]	$ 2,340,000
July	$ 29,424,000	[$ 28,748,000]	$ 676,000
August	$ 37,269,000	[$ 29,424,000]	$ 7,845,000
September	**$ 28,818,000**	[$ 37,269,000]	$ (8,451,000)
Total Test-Year			**$ (675,000)**

Unbilled revenues for the test year, a negative $675,000, equals the recorded unbilled revenues for September 2003, the last month of the test year, or $28,818,000, minus the unbilled revenues recorded for September 2002, the month prior to the beginning of the test year, or $29,493,000 (i.e., $28,818,000 – $29,493,000 = -$675,000). The unbilled revenues reversed in October 2002 exceeded the unbilled revenues added in September 2003. Therefore, KU had negative unbilled revenues during the test-year. Consequently, the recommendations made by the intervenor witnesses would result in a larger rate increase for KU customers.

Q. Are unbilled revenues during a 12 month period often negative?

A. Yes, they are. As can be seen from the above tables unbilled revenues were positive (a net credit) for LG&E and negative (a net debit) for KU.

Q. Did the Companies make pro-forma adjustments to eliminate unbilled revenues from test-year operating revenues?

A. Yes. Consistent with LG&E's last two rate cases (Case No. 2000-080 and Case No. 90-158), unbilled revenues were removed from test-year operating results.

Q. Did any of the intervenor witnesses make recommendations regarding the Company's pro-form adjustment?

A. Yes. KIUC witness Kollen, DOD witness Prisco, and AG witness Henkes offer three radically different recommendations regarding the treatment of unbilled revenues. Recommending that the Company's unbilled revenue adjustment be disallowed, Mr. Kollen[2] simply proposes to leave unbilled revenues in test-year operating results. Mr. Prisco[3] eliminates the Company's adjustment to test-year revenues and then inexplicably amortizes the unbilled revenues at the *beginning* of the test-year over a ten-year period. In stark contrast to the other two witnesses, Mr. Henkes[4] proposes to remove unbilled revenues from

2 Direct Testimony of Lane Kollen, pp. 7-9.
3 Direct Testimony of Thomas J. Prisco, p. 8.
4 Direct Testimony of Robert J. Henkes, pp. 27-29.

test-year operating results, consistent with the Companies' proposal, but curiously recommends attributing expenses to those unbilled revenues.

Q. Did Attorney General witness Majoros propose an unbilled revenue adjustment for KU?

A. No. Because KU had negative unbilled revenues during the test year, an unbilled adjustment for KU would have resulted in a greater increase. This is one of many inconsistencies between the positions taken by Mr. Henkes for LG&E and by Mr. Majoros for KU.

Q. Are there any problems with leaving unbilled revenues in test year operating results as proposed by Mr. Kollen and Mr. Prisco?

A. Yes. Besides being contrary to past Commission practice, there are numerous problems with leaving unbilled revenues in test-year operating results. One of the more glaring problems is that Mr. Kollen and Mr. Prisco add unbilled revenues to test-year income that include revenue amounts related to gas costs, fuel costs, environmental costs, demand-side management costs and other items that have 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 GSC, FAC, ECR, DSM, and other components of the rates. For example, the average price used to compute unbilled gas revenues for September 2003, was $12.26, which included a GSC component of $8.03. However, the gas supply expenses associated with the GSC component of the rate have been removed from test-year operating expenses.

Mr. Kollen and Mr. Prisco have added unbilled revenues to the test year that include revenues for the GSC, FAC, ECR, DSM and other components of the gas and electric rates even though the costs for these components have been eliminated from operating expenses. 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 36 of Rives Exhibit 1. FAC costs were eliminated from operating expenses through the pro-forma adjustment shown on line 5 of Rives Exhibit 1. ECR costs were eliminated from operating expenses through the pro-forma adjustment shown on line 6 of Rives Exhibit 1. DSM costs were eliminated from operating expenses through the pro-forma adjustment shown on line 12 of Rives Exhibit 1. By adding unbilled revenues that include recoveries for these costs, Mr. Kollen and Mr. Prisco have penalized the Company by seriously overstating test year revenues.

Q. Are there any other problems with the unbilled revenue adjustments proposed by Mr. Kollen and Mr. Prisco?

A. Yes. In addition to the unbilled revenues being significantly overstated by the inclusion of GSC, FAC and ECR revenues, Mr. Kollen and Mr. Prisco fail to account for the fact that various pro-forma adjustments in the rate case eliminate the need to consider unbilled revenues. The failure to consider the normalizing effect on test-year revenues and expenses of pro-forma adjustments underscores the fallacy in not only Mr. Kollen's and Mr. Prisco's recommendations, but also Mr. Henkes's illogical idea that an expense adjustment should be made to reflect the proper elimination of unbilled revenues. Through the proper application of normalization adjustments, any need to even consider unbilled revenues disappears. If revenues and expenses are properly normalized 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 GSC, FAC, ECR, DSM, 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 normalize 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 for a 12-month period would be insignificant. In fact, if such changes did not occur, then billing-cycle and calendar-month revenue for any 12-month period would be virtually identical because the unbilled amount subtracted out during the period (i.e., the unbilled revenues for the month immediately prior to the 12-month period) would be approximately the same as the unbilled amount added to the period (i.e. the unbilled revenues for the last month of the 12-month period). Likewise, if the utility's revenues and expenses are properly normalized 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 September 2003 and subtracting the unbilled revenues for September 2002. If the price in September 2003 is different than it was in September 2002, 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 September 2002 to September 2003. Even though there was no change in the LG&E's base rates from September 2002 to September 2003, the average price used to compute unbilled revenues increased from $7.87/Mcf to $12.26/Mcf, due to increased gas costs. This increase in price accounts for almost all of LG&E's unbilled gas revenues. By eliminating the GSC, ECR, DSM, and other components from revenues and expenses, as was done in the Companies' rate case applications, any unbilled revenues created as a result of changes in 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 (September 2003) than for the month that is subtracted (September 2002) 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 13 of Rives Exhibit 1) and to reflect customer rate switching and customer plant closing (line 31 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 (September 2003) than there were during the month that was subtracted out (September 2002) 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 operations to adjust revenues for normal temperature (line 38 of Rives Exhibit 1). Therefore, any unbilled revenues created as a result of changes in temperature have been eliminated through the temperature normalization adjustment.

The example provided in Seelye Rebuttal Exhibit 1 illustrates how changes in temperature and changes in the number of customers create unbilled revenues. This example shows a customer class consisting of 1,000 customers with a base load of 1.5 Mcf per month and temperature sensitive load of 0.0151 Mcf per degree day. As can be seen on page 1 of this exhibit, if temperatures are normal in September 2002 and September 2003 and there are no changes in customers, then there are no unbilled revenues, demonstrating how the temperature normalization and year-end adjustments eliminate the need to include unbilled revenues. Page 2 of Seelye Rebuttal Exhibit 1 shows that if there were 64 more degree days than normal in September 2002, but no change in the number of customers, then the unbilled revenues for the 12 month period would have been a debit of $741.81. Page 3 shows that if there is a difference of 500 customers served during these two months, but normal temperatures in both months, then unbilled revenues of $208.63 will be created during the test year. Making normalization adjustments in a rate case eliminates the need to consider unbilled revenues. If revenues and expenses are properly normalized through the proper application of pro-forma adjustments, there will not be any unbilled revenues.

Q. Are there any other problems with the intervenor witnesses' recommendation of including unbilled revenue adjustments in test year operating results?

A. Yes. Mr. Kollen and Prisco proposed to eliminate the unbilled revenue adjustment without proposing to modify 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.

A likely reason that neither witness attempted to restate the billing determinants used to develop rates is that billing units associated with the unbilled revenues do not exist for each rate class. As explained earlier, unbilled revenues are not estimated for each rate class. The billing determinants used to develop the proposed gas rates in Seelye Exhibit 14 and the proposed electric rates in Seelye Exhibit 29 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 14 and Seelye Exhibit 29. 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 Companies' proposed rates. The results of this reconciliation to as-billed revenues are shown for gas as-billed revenue in Seelye Exhibit 12 and for electric as-billed revenues in Seelye Exhibit 27. 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 12 and 27, and the development of the proposed rates in Seelye Exhibits 14 and 29, the gas and electric year-end adjustments shown in Seelye Exhibits 9 and 25 and the gas temperature normalization adjustments shown in Seelye Exhibit 8 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. If unbilled revenue is included and all adjustments are made using billing determinants that properly reflect unbilled revenues, then the revenue requirements and resulting rates should be the same as eliminating unbilled revenues and calculating the adjustments using as-billed revenue requirements. This point was made in testimony presented by Benjamin A. McKnight testifying on behalf of LG&E in Case No. 90-158:

> Q Mr. McKnight, now that LG&E has adopted the unbilled method for revenues recognition, should test period revenues also be determined on the unbilled basis?
>
> A. It really does not matter whether test period revenues are determined on the billed or unbilled basis. Given the adjustments to the test year operating revenues [made by the Company], either method properly applied should yield substantially the same result. Both methods should result in a representative 12-month level of operating revenues for purposes of setting future rates. For ratemaking purposes, the billed method has a practical advantage of having fewer estimates than are necessary for reporting unbilled revenues for financial reporting purposes.
>
> (Testimony of Benjamin A. McKnight, Case No. 90-158, pages 9-10.)

The Commission accepted the use of as-billed revenues in Case No. 90-158 and again in Case No. 2000-080, LG&E's last gas base rate case.

Q. Do you have any further comments concerning Mr. Prisco's recommendation?

A. Yes. Like Mr. Kollen, Mr. Prisco proposes to add unbilled revenues to test-year operating results. But then, quite inexplicably, he amortizes the unbilled revenues at the *beginning* of the test-year (i.e., the amount for September 2002 that was subtracted out of the test year) over a ten-year period. I am utterly perplexed by Mr. Prisco's recommendation, the sole purpose of which appears to be to produce a lower revenue requirement. Mr. Prisco does not explain why it would be reasonable to amortize the unbilled revenues recorded for September 2002. He merely states:

> The Commission may not agree with the actual mechanics of my adjustment [;] however, action needs to be taken to mitigate the growth of unbilled revenues, and the monetary impact it can have on customers as a result of the ESM calculation. (Direct Testimony of Thomas J. Prisco, page 8.)

In addition to expressing doubts about his own recommendation, Mr. Prisco fails to provide evidence supporting his claim that there has been "growth" in unbilled revenues or an analysis of the monetary impact that unbilled revenues have on the ESM calculation.

Q. You mentioned earlier that Mr. Henkes does not propose to include unbilled revenues in test-year revenues, but rather adjusts expenses to correspond to the unbilled revenues. Is there any merit to this approach?

A. No. The underlying concept behind Mr. Henkes's approach is that an expense adjustment should be made to reflect the adjustment made to eliminate unbilled revenues. The only advantage to Mr. Henkes's approach over the proposals of the other two witnesses is that there is no need to be concerned about adjusting the billing determinants used to develop rates. Since Mr. Henkes is not including unbilled revenues in the test-year operating results, there is no need to reconcile the billing units to reflect the unbilled revenues. Otherwise, his proposal suffers from the same problems that pervade Mr. Kollen's and Mr. Prisco's proposals.

It is also important to note that Mr. Henkes is performing a flip-flop of sorts on this issue. Mr. Henkes submitted testimony on behalf of the AG in LG&E's last base gas rate case (Case No. 2000-080). Although several data requests were submitted by the AG in Case No. 2000-080 concerning unbilled revenues, Mr. Henkes did not propose to make an expense adjustment to reflect the elimination of unbilled revenues in that proceeding. Yet in the current proceeding, rather than being guided by sound ratemaking principles, Mr. Henkes has developed a creative new way to penalize the Companies – he applies the operating ratios used in the Companies' year-end adjustments to every revenue adjustment in sight, regardless of whether it makes any sense to perform such an adjustment.

Mr. Henkes's recommendation is no more valid than those of the other two witnesses. His approach runs contrary to prior Commission practice – and, as already mentioned, runs contrary to his own prior practice. In computing the expense adjustment, Mr. Henkes applies an operating ratio to revenues that include GSC, FAC, ECR, DSM, and other components of revenue that have been removed from test-year operating results. He fails to consider that the pro-forma adjustments made in the proceeding already account for any mismatch in revenues and expenses that might otherwise occur. For example, he neglects to explain why it is appropriate to adjust gas operating expenses to account for an unbilled revenue adjustment that relates almost exclusively to changes in gas supply expenses from September 2002 to September 2003. Any changes in gas costs or other cost components recovered through the FAC, ECR, DSM have been fully accounted for through the elimination of the revenues and costs of these items from test-year operating results.

(d) Henkes's Application of an Operating Ratio to Revenue Adjustments

Q. What is your view of Mr. Henkes's use of operating ratios in this proceeding?

A. It is unconventional to say the least. He develops an expense adjustment by applying an operating ratio to several pro-forma revenue adjustments – namely, the gas temperature normalization adjustment, the gas plant closing adjustment, and the electric ECR roll-in adjustment.

Q. Has the Company ever made such adjustments in prior rate cases?

A. No.

Q. Has the Commission ever required such adjustments in prior LG&E rate cases?

A. No.

Q. Did Mr. Henkes propose such an adjustment in LG&E's last gas base rate case?

A. No. Although there were similar revenue adjustments in Case No. 2000-080, Mr. Henkes did not propose such an adjustment in that proceeding. In this rate case, Mr. Henkes is advancing a new, unconventional concept.

Q. Did Mr. Majoros propose similar adjustments for KU?

A. No. This is another inconsistency in the positions taken by Mr. Henkes for LG&E and by Mr. Majoros for KU.

Q. Can any of these expense adjustments be supported?

A. Only one. The application of the operating ratio to the plant closing adjustment is not unreasonable. However, as will be explained below, applying the operating ratio to the gas temperature normalization adjustment and electric ECR roll-in adjustment is without merit.

Q. How does Mr. Henkes determine the expense adjustment?

Mr. Henkes develops the expense adjustment by applying an operating ratio to several pro-forma revenue adjustments – namely, the gas temperature normalization adjustment, the gas plant closing adjustment, and the electric ECR roll-in adjustment. He uses the same operating ratio that was used in computing the expense component of the Company's year-end adjustment. In calculating expenses for the year-end adjustment, LG&E has traditionally applied an operating ratio to the revenue component of the adjustment. The revenue component of the year-end adjustment is determined by calculating the difference between the number of customers at the end of the test-year and the average number of customers during the test year, and then multiplying this difference by the average normalized revenue per customer for each rate class. The operating ratio is computed as the ratio of net revenues to net expenses. The theory behind the year-end adjustment is that since rate base and capitalization are determined as of the end of the test year, then revenues and associated expenses should also be adjusted to reflect the number of customers served at the end of the year. Determining the revenues associated with the difference in customers at the end of the test year compared to the average number during the test year is relatively straightforward. Measuring the additional expenses related to serving more customers is less straightforward, since it can be argued that not all expenses change in direct proportion to increases in the number of customers. It is for this reason that certain expenses have been removed from "net revenue" in the computation of the operating ratio; for example, the Commission has traditionally required the removal of wages and salaries, pensions and benefits, and regulatory commission expenses in determining net revenue.

Q. Why is it inappropriate to apply the operating adjustment to the temperature normalization adjustment or to the ECR roll-in?

A. While it clearly costs more for LG&E to serve additional customers, there are no material incremental costs, other than gas supply costs (which have been removed from test-year operating results), associated with variations in sales due to changes in temperature. Adding customers to the system certainly results in additional expenses – e.g., billing expenses, meter reading expenses, meter testing expenses, service line inspections and other service related expenses, main expenses, regulator expenses, etc. LG&E's non-gas supply expenses, however, simply do not vary significantly with changes in sales due to weather. Other than gas supply costs (which have been removed) the only expense that I am aware of that varies in proportion to changes in temperature-sensitive sales is the cost of mercaptan -- which is the chemical added to natural gas that gives it that distinctive odor. The change in the cost of mercaptan resulting from any change in temperature-sensitive sales is simply not material. In total, LG&E only spends about $50,000 on mercaptan per year. Likewise, there is no change in expenses associated with the ECR roll-in that has not been accounted for in the roll-in of environmental costs in revenue requirements. Applying the operating ratio to these revenue items is illogical, contrary to past Commission practice, contrary to recommendations made by Mr. Henkes in previous rate cases, and punitive.

Q. But why is it not unreasonable to apply the operating ratio to the plant-closing adjustment?

A. Although the operating ratio has not been applied to the plant closing adjustment in prior proceedings, it is not unreasonable to apply the operating ratio to this adjustment. The loss of customers reflected in the plant-closing adjustment will presumably offset the increase in customers reflected in the year-end adjustment. For this reason, the Company is not taking issue with Mr. Henkes's proposal to apply an operating ratio of 0.2987 to the plant-closing revenue adjustment of $34,719 shown on Rives Exhibit 1, Schedule 1.28. This would result in a decrease in gas operating expenses of $10,371 ($34,719 x 0.2987), before income taxes.

(e) Year-End Adjustment

Q. Does Mr. Henkes recommend a non-standard approach for calculating the revenue component of the electric and gas year-end adjustment?

A. Yes. The same methodology has been used for many years in computing the revenue component of the year-end adjustment. As explained earlier, the theory behind the year-end adjustment is to restate revenues and expenses to reflect the difference between (i) the number of customers served as of the end of the test year and (ii) the average number of customers served during the test year as reflected in operating revenues and expenses. Because rate base and capitalization are valued as of the end of the test year, the Commission determined many years ago that it would be appropriate to make a year-end adjustment to place revenues and expenses on the same footing as year-end rate base. The revenue component of the year-end adjustment is therefore computed by measuring the difference between the number of customers at the end of the test-year and the average number of customers during the test year, and then multiplying this difference by rate class to the average normalized revenue per customer.

Q. Is the methodology that Mr. Henkes uses consistent with the one traditionally used by the Commission?

A. No. Mr. Henkes's approach cobbles together two different methodologies – one for residential customers and another for other classes. In my opinion both methodologies are flawed. For the ***non-residential*** classes he uses the results of year-end calculation submitted by LG&E in its responses to data requests from the Commission Staff – specifically, the Company's responses to Question No. 24 (gas customers) and Question No. 28 (electric customers) to the third data request of the Commission Staff dated March 1, 2004. In these responses, the year-end adjustments for gas and electric operations were calculated by computing the difference between year-end customers and the average number of customers for the 13-month period ending September 30, 2003. For the *residential* rate classes, Mr. Henkes applies a 5-year compound growth rate to the 13-month average customers to determine year-end customers.[5]

Q. Is there any basis for using a 5-year compound growth rate to compute the year-end adjustment for the residential rate classes?

A. No. Mr. Henkes's approach is not consistent with the reason that the year-end adjustment is made in the first place. As already explained, the purpose of the year-end adjustment is to place revenues and expenses on the same footing as year-end capitalization and rate base. The year-end adjustment is not made to capture the 5-year compound growth in the number of customers. The capitalization and rate base shown on Rives Exhibit 2 and Rives Exhibit 3 were not computed by applying a 5-year trend factor to the 13-month average capitalization and rate base. It is inconsistent and misguided to apply a 5-year trend factor to the 13-month average customers when capitalization and rate base are not determined in the same manner.

Mr. Henkes's trend analysis would increase test-year gas revenues for the residential class by $304,994[6] and would increase test-year electric revenues for the residential class by $200,801[7].

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5 Mr. Henkes refers to this as a "Test Year Customer Growth Adjustment". See Schedule RJH-7 of the Direct Testimony and Exhibits of Robert J. Henkes Pertaining to the Electric Rate Case and Schedule and RJH-7 of the Direct Testimony and Exhibits of Robert J. Henkes Pertaining to the Gas Rate Case

6 LG&E's year-end adjustment shown in Seelye Exhibit 9 resulted in an increase of $114,237 for the residential class, whereas Mr. Henkes's adjustment shown on Schedule RJH-7 would result in an increase of $419,231, for a

Q. Are there any other problems with using a 5-year compound growth rate to calculate the residential year-end adjustment?

A. Mr. Henkes simply computed the average compound growth rate based on the difference in customers from 1999 and 2003. He merely compares customers in 2003 to customers in 1999 – in other words, he compares end-point to end-point. He fails to demonstrate why the growth rate in years prior to the test year (e.g., 1999 through 2002) provides any insight whatsoever about customer changes during the test year. He fails to explain how customer growth from 1999 to 2003 sheds any light on the number of customers that the Company is now adding, especially since LG&E was adding more customers a few years back than it added during the test year. He also fails to explain how customer growth from 1999 to 2003 is related to test-year-end capitalization and rate base. In making a year-end adjustment, the only factor that is relevant is how year-end customers compares to the average number of customers during the test year.

Q. Did Mr. Henkes recommend the use of a trend-factor in determining the year-end adjustment in LG&E's last gas base rate case?

A. No. In his testimony submitted in LG&E's last gas base rate case (Case No. 2000-080), Mr. Henkes did not express any objections to the methodology used by LG&E to calculate the year-end adjustment. In this proceeding Mr. Henkes has invented a new, results-oriented methodology for computing a year-end adjustment designed with the sole purpose of

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difference of $304,994.

7 LG&E's year-end adjustment shown in Seelye Exhibit 25 resulted in an increase of $1,232,279 for the residential class, whereas Mr. Henkes's adjustment shown on Schedule RJH-7 would result in an increase of $1,433,080, for a difference of $200,801.

lowering the rate increase, using an approach that disregards sound regulatory practice and prior Commission practice.

Q. You indicated earlier that Mr. Henkes used a different methodology for the non-residential rate classes. Do you agree with the methodology he recommends for the non-residential classes?

A. No. As I mentioned earlier, Mr. Henkes's proposed adjustment combines a mishmash of methodologies. For non-residential rate classes, his proposed year-end adjustment is computed by measuring the difference between customers as of the end of the year and customers during a 13-month average. Although I have fewer problems with the use of a 13-month average to determine the year-end adjustment than with the 5-year trend factor that Mr. Henkes used for the residential rate classes, the use of a 13-month average is inappropriate for a number of reasons. First, it departs from the methodology that has been used for many years to calculate the year-end adjustment. Second, there is no sound basis for using a 13-month average as opposed to a 12-month average. Test-year operating results include 12 months of revenues and expenses, not 13 months of revenues and expenses, nor 12 months of revenues and expenses based on a 13-month average. In my opinion, the use of a 13-month average is not consistent with adjusting test-year revenues and expenses (for 12 months) to reflect year-end customers. Third, the use of a 13-month average is results-driven rather than based on sound regulatory theory.

Q. Did Mr. Majoros propose a similar adjustment for KU?

A. No.

(f) ECR Roll-in

Q. There were several data requests from the Commission Staff about LG&E's proposed treatment of environmental costs in this proceeding. Could you describe how the Companies propose to handle environmental costs currently recovered through the ECR?

A. Yes. The Companies propose to include all costs associated with their original environmental compliance plans[8] in revenue requirements in this proceeding and to discontinue recovering these costs through the environmental surcharge. In other words, the KU and LG&E are proposing to terminate the surcharges on their original environmental plans. The Companies propose to continue to recover the costs associated with subsequent environmental plans (KU's Post 94 Plan and LG&E's Post 95 Plan) through the environmental surcharge. Since the Company contemplates that the costs of the subsequent plans will continue to be recovered through the environmental surcharge, a pro-forma adjustment was made to remove all revenues and expenses associated with these plans from test-year operating results. The revenues and expenses associated with the subsequent plans were eliminated through the application of the pro-forma adjustment identified as Reference Schedule 1.03 of Rives Exhibit 1. LG&E's electric capitalization was also adjusted to eliminate the net investment associated with these plans.

It is important to understand that the expenses associated with the original environmental compliance plans were not eliminated from test-year expenses. Likewise, the net investments associated with these plans were not eliminated from capitalization.

8 KU's original environmental compliance plan (the "1994 Plan") was approved in Case No. 93-465 and LG&E's

Consequently, all costs associated with the original environmental compliance plans are *included* in test-year revenue requirements. As mentioned earlier, under the Companies' proposal the environmental surcharge calculations would be modified to remove costs associated with the original environmental compliance plans.

It is also important to understand that the revenues associated the original environmental compliance plans (including amounts rolled in) were not eliminated from test-year revenues. Because these costs would not be recovered through the ECR, these revenues are included in test-year operating results. However, if the Companies proposed treatment of these costs is rejected and the costs associated with the original plans continue to be tracked through the ECR it will be necessary to reduce test-year revenues to reflect these rolled-in revenues.

Q. Why are the Companies proposing to include the costs associated with the original environmental compliance plans in revenue requirements?

A. In my opinion, this is the approach contemplated in the statute permitting the recovery of compliance costs through the environmental surcharge, KRS 278.183. I was personally involved in the development of LG&E's 1995 Plan and in the development of the environmental surcharge mechanism proposed in Case No. 94-332. At that time, it was LG&E's expectation, and I believe that of KU as well, that these costs would be included in revenue requirements whenever the Company filed its next general rate case. KRS 278.183 served as a bridge to allow electric utilities the opportunity to recover incremental environmental costs through the environmental surcharge – many of which were required

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original environmental compliance plan (the "1995 Plan") was approved in Case No. 94-332.

because of amendments to the federal Clean Air Act – until those costs could be included in base rates in a general rate case. The purpose of KRS 278.183 was to place coal-fired generation burning high-sulfur Kentucky coal on an equal cost recovery footing with compliance coal or installing gas-fired generation or other technologies. Since the cost of compliance coal or natural gas could be automatically flowed through the FAC, the environmental surcharge statute was implemented to facilitate cost recovery of non-fuel options such as installing scrubbers to remove SO_2 when burning high-sulfur Kentucky coal. I can say with certainty that LG&E would not have proposed a rate of return that only reflected the cost of pollution control bonds had it anticipated that this investment would not be included in capitalization in its next rate case and not be allowed to earn a fair, just and reasonable return. In Case No. 94-332, M. Lee Fowler[9] testified as follows:

> **Q. Has LG&E determined a reasonable rate of return to apply to eligible expenditures? If so, please state the rate and explain why this rate was selected.**
>
> A. Yes. LG&E has determined that a rate of return of 5.60 percent is reasonable for purposes of calculating an environmental surcharge. *This return is recommended to be used until LG&E's next general rate case when the Public Service Commission will approve a rate of return to be applied to all capital expenditure, including the environmental costs.*
>
> (Prepared Testimony of M. Lee Fowler, Case No. 94-332, page 6. Emphasis supplied.)

Therefore, when LG&E filed the 1995 Plan, it was certainly we anticipated that these costs would be included in revenue requirements in the next rate case.

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9 Mr. Fowler was Vice President and Controller for LG&E prior to his retirement.

Q. Why is it preferable to include the costs associated with the original plans in revenue requirements in these proceedings and discontinue the recovery of these costs through the environmental surcharge?

A. There are several reasons why the Companies prefer to include these costs in revenue requirements in this proceeding. First, the projects included in the original plans are essentially complete. Second, the methodology proposed by the Company allows us to terminate the surcharges for KU's 1994 Plan and LG&E's 1995 Plan – to put them to bed, so to speak. Third, including these costs in revenue requirements is the most straightforward way to incorporate these costs in base rate revenue requirements. The advantage of including these costs in revenue requirements for the rate case and terminating the environmental surcharge on these costs is that they will be rolled into base rates just like any other cost, thus eliminating the need to continue showing an ECR on these amounts for years to come. In other words, the methodology proposed by KU and LG&E does not perpetuate an environmental surcharge on the original environmental compliance plans.

Q. Are there other alternatives that will continue to provide recovery of these original plan costs through the environmental surcharge and permit the Companies an opportunity to earn a fair, just and reasonable return on its investment?

A. Yes. There are at least two alternative approaches that would permit these costs to continue to be recovered through the environmental surcharge but provide the Companies the opportunity to earn, a fair just and reasonable return on their investments. One approach would be to remove all revenues, expenses and investment from test-year results. This approach would require the following adjustments in addition to those already included in the

Rives Exhibit 1: (i) reduce test-year operating revenues by the revenues rolled into base rates for the original environmental compliance plans, (ii) reduce test-year operating expenses by the expenses incurred during the 12 months ended September 2003 associated with the original environmental compliance plans, and (iii) reduce the debt component of the Companies' capitalization by the net investment as of the end of the test year for the original environmental compliance plans. The reason that only the debt component should be adjusted – and not total capitalization – is that the return currently utilized in the environmental surcharge on the original plans is the return on pollution control bonds. Since only debt costs are recovered through the environmental surcharge on the environmental compliance plans, if these investments are removed from capitalization then only debt costs should be removed.

Q. What is the second alternative for continuing to recover costs associated with the original environmental compliance plans through the environmental surcharge but still providing the Companies the opportunity to earn a fair, just and reasonable return on their investments?

A. The second alternative would be to include the total investment and expenses that have been rolled into base rates for both the original environmental compliance plans and subsequent plans in the test-year revenue requirements for both utilities. With this approach, the rate base and expenses corresponding to the surcharge percentage rolled into base rates in Case No. 2002-00193 for LG&E and in Case No. 2003-00068 for KU would be included in the capitalization and expenses for the test year. Revenues from the roll-in would also be included in test-year revenues. The difference between test-year rate base and the rolled-in level would be removed from the debt component of capitalization, and the difference between test-year expenses and the rolled-in expenses would be removed from expenses during the test year. Test year revenues would be adjusted to remove ECR revenues net of the rolled-in amounts. If we understand the data requests correctly, this approach would correspond to the methodology suggested in Question 34 to KU and Question 38 to LG&E of the Commisison Staff's second data request dated February 3, 2004, in this proceeding.

Q. Do you have any fundamental problems with either of these alternatives?

A. No. Either of these alternatives would allow the Companies the opportunity to recover their original plan costs, including a fair, just and reasonable return on their investments. Our preference, however, is to terminate the ECR surcharge for the original compliance plans.

(g) Off-System Sales in the ECR and Adjustment for Mismatch in Fuel Cost Recovery

Q. Are the intervenor witnesses being evenhanded about two errors that were made in the off-system sales revenue adjustment for the ECR calculation and in the adjustment for the mismatch in fuel cost recovery for the year ending September 20, 2003?

A. No. In preparing responses to data requests submitted by the Commission Staff, the KIUC and the AG, it came to our attention that there were errors in the off-system sales revenue adjustment for the ECR calculation, Reference Schedule 1.05 of Rives Exhibit 1 and in the adjustment concerning the mismatch in fuel cost recovery for the test year, Reference Schedule 1.01 of Rives Exhibit 1. Even though the errors were fully explained in responses to data requests[10], witnesses for the KIUC and AG ignored these errors in presenting their recommended revenue requirements, apparently because correcting the errors would increase the Companies' revenue requirements.

Q. Please explain the adjustment and the nature of the error relating to the adjustment in the off-system sales revenue for the ECR.

A. In the Companies' environmental surcharge calculations, a portion of the environmental costs incurred is allocated to off-system sales. The Commission determined in approving the Companies' ECRs that it is appropriate to allocate a portion of environmental costs to off-system sales by observing that environmental costs are incurred to make off-system sales just as they are to make retail sales. The purpose of the pro-forma off-system sales revenue adjustment for the ECR calculation (Reference Schedule 1.05) is to adjust off-system sales margins, which are credited against revenue requirements in the rate case, for the environmental costs allocated to off-system sales in the monthly environmental surcharge calculations. This adjustment was approved in Case Nos. 98-426 and 98-474 and recognized in all subsequent ESM filings.

In the original calculation of this adjustment, inter-company revenue was subtracted from total off-system sales revenue to determine the environmental costs for off-system sales that should be subtracted from revenues from off-system sales in this proceeding. When preparing a response to a KIUC data request, we realized that intercompany revenues <u>*should not have been*</u> subtracted from off-system sales revenue. Environmental costs are allocated to

10 The error was explained in the supplemental responses to question 54 to LG&E and question 69 to KU of the first data request of the KIUC dated February 3, 2004, and filed February 27, 2004. The error was also brought to light in LG&E's response to question 53 of the supplemental data request of the Attorney General dated March 1, 2004.

intercompany revenue in the monthly environmental surcharge calculations. However, there is no mechanism in place for recovering these costs from ratepayers. Although KU pays LG&E (and vice versa) for the cost of the intercompany sales, KU does not pay LG&E for the portion of environmental costs allocated to intercompany sales in the environmental surcharge calculations. These costs are not recovered through either LG&E or KU's ECR mechanism, nor are they recovered through either utility's FAC. Intercompany revenues represent charges paid by one utility for transfers of electric energy to the other. Therefore, unless these environmental costs are subtracted from intercompany revenues in this proceeding, the Companies will be denied the opportunity from ever recovering these legitimately incurred costs. It is thus reasonable that LG&E and KU be allowed to revise Reference Schedule 1.05 of Rives Exhibit 1 to correct for this oversight.

Q. Have you prepared a revised Reference Schedule 1.05?

A. Yes. Revised Reference Schedule 1.05 for LG&E and KU are included as pages 1 and 2 of Seelye Rebuttal Exhibit 2.

Q. Please explain KU's adjustment and nature of the error relating to the mismatch in fuel cost recovery for the test period.

A. As I discussed in my direct testimony, via this adjustment, the mismatch between fuels costs and fuel cost recovery through KU's FAC will be eliminated consistent with Commission practice. An error was detected, however, in PSC 2-15(a), when the Commission Staff noted that the expense amount shown in the proposed adjustment was taken from KU's Form A filing for November, 2003 made on December 16, 2003. In fact, the expense amount included on that Form A for September 2003 was incorrectly listed as $4,269,288, when it actually should have been $1,099,278. As a result, KU later filed a revised Form A for the same period on December 31, 2003. This correction results in an adjustment of $7,412,961, rather than $4,242,951, to KU's net operating income.

Q. Has the Company filed a revised Reference Schedule 1.01?

A. Yes. Revised Reference Schedule 1.01 for KU was filed on February 17, 2004 in Response to PSC 2-15(a). A copy of this revised schedule is included as page 3 of Seelye Rebuttal Exhibit 2.

(h) Purification Expenses and Storage Field Losses

Q. Do you have any comments about Mr. Henkes's disallowance of the Company's proposed purification expense and storage field losses adjustment?

A. Yes. A pro-forma adjustment was made to restate LG&E's purification expense and storage field losses to reflect the cost of natural gas stored underground at the end of the test year. Because purification expenses and storage field losses are determined monthly based on the average cost of gas withdrawn from storage, it is reasonable to use the inventory cost of the gas at the end of the test year rather than actual expenses during the test year. Mr. Henkes argues that the cost of storage at the end of the test year is no more representative of what the cost will be when the rates go into effect than the actual costs during the test year. Mr. Henkes's argument is flawed for several reasons. First, on a theoretical level, changes in natural gas prices can be described as a stochastic process. It is a fundamental principle of stochastic processes that the current value of a random variable is a better indicator of future values than those experienced in the past.[11] For example, the price of gasoline at the pump today is generally a better predictor of future prices than the price we were seeing twelve months ago. Second, the price of natural gas has gone up since the end of the test year. The NYMEX price of natural gas was $4.830/Mcf on September 30, 2003, and was $5.553/Mcf on April 20, 2004. Third, Mr. Henkes ignores the fact that September 30, 2003, was toward the end of LG&E's injection season; therefore, there have not been significant injections since the end of the test year. The cost of gas stored underground was $5.423 at the end of March 2004 compared to $5.373 at the end of the test year.

I fully agree with one point that Mr. Henkes makes. On page 47 of his testimony he indicates that gas prices are highly volatile. He is absolutely correct on this point. In fact, natural gas exhibits price volatility that exceeds most other commodities. Because of the potential volatility in these expenses, it would be reasonable to remove purification expenses and storage field losses from base rate revenue requirements and allow the Company to recover these expenses through the Gas Supply Clause. The advantage of this approach is that it would provide on-going recovery of actual costs through the Gas Supply Clause rather than establishing a fixed base rate amount that may provide for recoveries that differ from actual costs on a going forward basis. In other words, recovering these costs through the Gas

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11 For example, see Paul Wilmott, Sam Howison, and Jeff Dewynne, *The Mathematics of Financial Derivatives* (Cambridge University Press, 1995), page 23, where the authors state:

> Suppose that today's date is t_0 and today's asset price is S_0. If the price at a later date t', in six months' time, say, is S', then S' will be distributed about S_0 with a probability density function [described above]. The future asset price, S' is thus more likely to be close to S_0 and less likely to be far away. The further t' is from t_0 the more spread out this distribution is.

Supply Clause should alleviate Mr. Henkes's concern that LG&E will over-recover these expenses.

Q. Do you have any other comments about Mr. Henkes's testimony regarding this issue?

A. Yes. I want to point out a mischaracterization (or misunderstanding) of a statement quoted by Mr. Henkes from one of LG&E's responses to a data request. On page 49 of his testimony, Mr. Henkes indicates that LG&E claimed in its response to PSC-3-25(a) that the Commission approved the Company's proposed treatment of purification expenses and storage field losses in its previous rate case. Mr. Henkes apparently misunderstood LG&E's response to this data request. The response was referring to the methodology used to determine the physical volume of storage losses, not to any pro-forma adjustment of these expenses that the Company proposed in Case No. 2000-080. Natural gas prices were much more stable when LG&E filed its last gas base rate case; therefore, the Company did not propose an adjustment to these expenses in Case No. 2000-080.

(i) Weather Normalization

Q. Did Attorney General witness Majoros propose an electric weather normalization adjustment for KU?

A. Yes.

Q. Did Attorney General witness Henkes propose a weather normalization for LG&E?

A. No. Although the temperature patterns in LG&E's service territory are very similar to those in KU's service territory, Mr. Henkes did not propose a weather normalization adjustment for LG&E.

Q. Has either LG&E or KU ever proposed an electric weather normalization adjustment in a general rate case?

A. Yes, on many occasions. Most recently, LG&E submitted a proposed weather normalization adjustment in Case No. 10064.

Q. In Case No. 10064 did the Commission provide any guidelines for what might represent a reasonable weather normalization adjustment?

A. Yes. In Case No. 10064 the Commission indicated that a weather adjustment should be based on a sound statistical analysis, such as a multivariate regression analysis, that considered economic variables as well as weather variables. In Case No. 10064 the Commission criticized LG&E's weather normalization adjustment for not considering other variables that affect electric sales and revenue:

> Further, LG&E, in adopting its [weather normalization] adjustment methodology, has failed to follow previous Commission orders to consider other variables in addition to temperature when normalizing sales. The methodology chosen by LG&E neglects to consider other factors (i.e., personal income, employment, humidity, wind, etc.) that may affect test-year electricity usage. (Order in Case No. 10064 dated July 1, 1998, page 41.)

In the same Order, the Commission also criticized the Company's weather normalization adjustment for not performing an "econometric or regression analysis":

> [I]f LG&E desires to propose an electric temperature adjustment in future rate applications, it should develop a methodology that will accurately and appropriately match the random effects of weather to electricity consumption. Further, LG&E should provide adequate support to verify the accuracy and appropriateness of any model presented. The Commission will require that LG&E provide

> documentation, including adequate statistical analysis, sufficient to support the accuracy of the relationships in the methodology developed and submitted in subsequent rate cases. (Order in Case No. 10064 dated July 1, 1998, page 43.)

The Commission indicated that a weather adjustment should adjust to a range determined by a confidence interval about the mean rather than adjust to the mean temperature:

> The Commission is of the opinion that there is adequate evidence to suggest that a range of temperatures and not a specific mean temperature is a more appropriate measure of normal temperatures. As long as the temperature falls within these bounds then it is inappropriate to adjust sales for temperature. However, if the temperature falls outside those bounds then it is appropriate to adjust sales to the nearest bound. (Order in Case No. 10064 dated July 1, 1998, page 39.)

Q. In computing his weather normalization adjustment, did Mr. Majoros perform an econometric or regression analysis?

A. No.

Q. Did Mr. Majoros consider economic as well as weather variables?

A. No.

Q. Did Mr. Majoros consider a range determined by a confidence interval about the mean temperature?

A. No.

Q. Did Mr. Majoros consider heating as well as cooling degree days?

A. No. Mr. Majoros only examined departures from normal cooling degree days. A *cooling degree day* is the value determined by the mean daily temperature less 65° F. A *heating degree day* is value determined by 65° F less the mean daily temperature. Cooling degree days are used to determine whether temperatures during the summer cooling months are hotter than normal. Heating degree days are used to determine whether temperatures during the winter heating months are colder than normal. KU serves a large amount of electric space heating load. During the test year KU served over 165,000 all-electric residential customers (i.e., residential customers with electric space heating). As can be seen from the following table, KU's sales were greater during the winter heating months of December, January, February and March than during the summer cooling months of June, July, August, and September of the test year.

KENTUCKY UTILITY COMPANY
Monthly MWH Sales

Month	MWH Sales
Oct-02	1,454,927
Nov-02	1,344,988
Dec-02	1,646,924
Jan-03	1,774,854
Feb-03	1,771,287
Mar-03	1,563,240
Apr-03	1,333,109
May-03	1,373,737
Jun-03	1,395,498
Jul-03	1,670,923
Aug-03	1,651,506
Sep-03	1,669,177

Peak sales months Ignored by Mr. Mojoros

KU's sales are driven more by heating degree days than by cooling degree. Yet Mr. Mojoros focuses on cooling degree days and ignores heating degree days. While cooling degree days were below average during the test year, heating degree were higher than average. Seelye

Rebuttal Exhibit 3 shows the cooling and heating degree days for each month of the test year. Actual cooling degree days (CDD) were 512 below normal during the test year, but actual heating degree days (HDD) were 693 *above* normal during the test year. A properly constructed weather normalization adjustment would consider differences in heating degree days as well as differences in cooling degree days. Given the amount of space heating load on KU's system, had a properly constructed weather normalization adjustment been made, the adjustment to test-year revenues would have almost certainly been downwards rather than upwards as proposed by Mr. Majoros.

Q. Does the approach used by Mr. Majoros represent a reasonable methodology for performing a weather normalization adjustment?

A. No. Mr. Majoros computes the adjustment to revenues by simply multiplying half of the difference in revenue between the calendar year 2003 and the calendar year 2002. He then applies a "system wide gross margin" factor of 53.19% to determine the income effect. This approach is replete with problems. He fails to develop a functional relationship between sales and temperature. A standard approach for estimating electric temperature sensitive load is to perform a multivariate regression analysis using several years of monthly sales, heating degree day, cooling degree day, and economic data, using an equation such as the following:

$$\text{Sales} = \alpha_0 + \alpha_1\text{HDD} + \alpha_2\text{CDD} + \alpha_3\text{ECON}_a + \alpha_4\text{ECON}_a + \ldots$$

Where: *Sales* is the utility's kWh sales during a specified period

HDD is the measure of heating degree days during the period

CDD is the measure of cooling degree days during the period

$ECON_a$, …., $ECON_j$ are economic and other variables

Least squares or some other regression technique would be used to estimate the parameters α_0, α_1, α_2, α_3, ... of the equation. Normalized sales would then be determined by applying normal heating degree days, normal cooling degree days, and normal economic variables to the parameter estimates. Mr. Majoros made no attempt to describe statistically the relationship between KU's sales and the various factors that account for the variability in KU's sales. It is incorrect to assume, as Mr. Majoros does, that all of the variability in KU's sales can be accounted for by changes in cooling degree days. He makes no attempt to compute temperature-sensitive and non-temperature-sensitive components of sales and revenues, he makes no attempt to differentiate between heating load and cooling load, and he fails to identify economic variables that might account for changes in sales and revenues.

Q. Does Mr. Majoros utilize test-year revenues to perform his adjustment?

A. No. His analysis is based solely on a revenue comparison between two *calendar* years. Mr. Majoros provides no explanation for why he used calendar year rather than test-year data. Furthermore, Mr. Mojoros seems to be using the calendar year 2002 as a base line, even though temperatures during the Summer of 2002 were significantly higher than normal.

Q. Is there any basis for taking half of the revenue difference between two years to compute his weather adjustment?

A. No. Mr. Majoros's use of a 50% factor is arbitrary and without empirical justification. He provides no statistical analysis to support his assertion that 50% of the revenue difference between 2002 and 2003 is related to weather.

Q. Has Mr. Majoros supplied any statistical evidence that supports his claim that revenues during 2003 were "abnormally high"?

A. No.

Q. Did Mr. Majoris determine the weather normalization adjustment for each rate class.

A. No. The amount of temperature sensitive sales varies by rate class. For example, industrial customers have relatively little temperature sensitive sales. The standard approach is to perform the adjustment for each rate class and to incorporate the adjustment into the utility's rate calculations. For example, LG&E's gas temperature normalization adjustment was performed for each rate class and the adjustment was incorporated into Seelye Exhibit 14.

Q. Should Mr. Majoros's weather normalization adjustment be rejected?

A. Yes, absolutely. I want to make it clear that I'm not arguing against a weather normalization adjustment per se. However, should the Commission adopt an electric normalization adjustment in a base rate case proceeding, I would strongly recommend against using the unsound methodology proposed by Mr. Majoros.

III. Electric Cost of Service Study

Q. What is the purpose of a cost of service study?

A. The purpose of a cost of service study is to estimate the cost of serving each customer class. One of the primary objectives of a cost of service study is to determine the rate of return on rate base that the Company is earning from each rate class.

Q. Did you sponsor LG&E and KU's electric cost of service studies?

A. Yes. These cost of service studies were described in my direct testimony, and the study itself was included in Seelye Exhibit 16 through Seelye Exhibit 22 in my direct testimony for LG&E and in Seelye Exhibit 2 through Seelye Exhibit in my direct testimony for KU.

Q. Did any other witnesses submit electric cost of service studies in this proceeding?

A. Yes. Attorney General witness David Brown-Kinloch and KIUC witness Stephen J. Baron have submitted cost of service studies.

Q. Did either Brown-Kinloch or Baron actually perform a cost of service study?

A. No. Both witnesses made selective modifications to the Companies' cost of service studies that produced results favoring their special interests. Specifically, Mr. Brown-Kinloch only incorporated changes that shifted costs away from residential customers and onto other customers, especially industrial customers, and Mr. Baron only made changes that shifted costs away from large industrial customers.

By comparing the impact of the changes made by Mr. Brown-Kinloch and Mr. Baron on the class rates of return for residential and large industrial customers, the following table illustrates how the changes they make (especially those made by the AG's witness) to the Companies cost of service studies simply serve to promote their separate agendas:

Louisville Gas and Electric Company Rates of Return			
	AG Witness Brown-Kinloch's Version of the Cost of Service Study	**Company's Cost of Service Study As Originally Submitted**	**KIUC Witness Baron's Version of the Cost of Service Study[12]**
Residential	2.37%	1.51%	1.69%
Large Industrial (LP, LP-TOD & Special Contracts)	3.62%	5.14%	5.90%

Kentucky Utilities Company Rates of Return			
	AG Witness Brown-Kinloch's Version of the Cost of Service Study	**Company's Cost of Service Study As Originally Submitted**	**KIUC Witness Baron's Version of the Cost of Service Study**
Residential	1.21%	0.53%	0.65%
Large Industrial (LP, LCI-TOD, HLF & Special Contracts)	6.56%	7.89%	8.84%

For the large industrial rate classes, the rates of return from the Companies' cost of service studies fall between the rates of return calculated by Mr. Brown-Kinloch and Mr. Baron, and for residential rate classes, the rates of return from the Companies' cost of service studies are significantly below the rates of return calculated by Mr. Brown-Kinloch and are very close to (slightly below) the rates of return calculated by Mr. Baron.[13] The Companies' objective is simple and straightforward – as much as practicable we want to set rates that reflect the cost of providing service. Ultimately, the public interest is served by setting rates that reflect costs. Mr. Brown-Kinloch and Mr. Baron, on the other hand, promote special interests among the Companies' customers and therefore have their own special agendas to advocate. Consequently, both of their recommendations should be weighed very carefully. Because there is no reason for LG&E and KU to favor one customer class over the other, more weight should be accorded the Companies' recommendations regarding cost of service methodologies, the allocation of the revenue increase, and rate design.

Q. **Do you have any general comments about Mr. Brown-Kinloch's electric cost of service study?**

A. Yes. Mr. Brown-Kinloch assigns an unrealistically large percentage of fixed production costs to the off-peak period and an astonishingly small percentage to the peak period. Three costing periods were identified in the Companies' cost of service studies – the summer peak period, the winter peak period, and the off-peak period. The summer peak period basically covers the daytime hours during weekdays in the hot summer months when the load is the highest. The winter peak period basically covers the daytime hours during weekdays in the winter months when loads are moderately high due to meeting heating load. The off-peak hours occur during

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12 Mr. Baron presents the results of five cost of service studies using various methodologies for allocating production and transmission fixed costs. However, he relies on a modified version of the Company's BIP cost of service study for developing his recommendations concerning the allocation of the rate increase. The rates of return shown in the table reflect the results based on Mr. Baron's modified version of the Company's BIP cost of service study, as presented in Baron Exhibit ____(SJB-2) for KU and in Baron Exhibit ____(SJB-7) for LG&E.

the middle of the night and during weekends when the Companies generally sell much less electric energy.

Over the past 30 years or more, the driving force behind the construction of any new generation capacity on LG&E or KU's system has been the need to meet peak demands, especially summer peak demands. Therefore, it should be obvious that a greater portion of production plant costs (fixed production costs) should be assigned to the summer and winter peak periods than to the off-peak period.

Mr. Brown-Kinloch, however, assigns more than half (54.68%) of LG&E's fixed production costs to the off-peak period. The percentage of fixed costs assigned to the off-peak period is roughly equal to the amount of energy (kWhs) sold during the off-peak period, implying that it costs no more to serve customers during the off-peak period than during peak periods. This illogical result signals that something is profoundly wrong with Mr. Brown-Kinloch's cost of service study. LG&E must install enough generation capacity to meet the demand or load placed on the system by customers. No matter how they are calculated, customer demands are higher during the peak period than during the off-peak period. Proportionately more costs should be assigned to the summer and winter peak periods than to the off-peak period. In Mr. Brown-Kinloch's study, fixed production costs are assigned to the costing period almost in direct proportion to the amount of energy sold during each period, rather than in consideration of the demands placed on the system.

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13 Several of Mr. Baron's studies show lower rates of return for the residential class. The Summer/Winter CP cost of service study shows a rate of return of 1.17% for the residential class. See Baron Exhibit ____(SJB-9). The Summer CP cost of service study shows a rate of return of 1.43% for the residential class. See Baron Exhibit ____(SJB-10).

Q. What percentage of LG&E's fixed production costs was assigned to the off-peak period in your cost of service study?

A. In the cost of service study presented in my direct testimony, 33.58% of LG&E's fixed production costs were assigned as "non-time differentiated", which means that 33.58% were allocated on the basis of annual energy (including energy during all three costing periods). In LG&E's cost of service study 26.45% was assigned to the summer peak period and 39.97% was assigned to the winter peak period. Mr. Brown-Kinloch assigned 18.11% to the summer peak period and 27.20% to the winter peak period. In my opinion, Mr. Brown-Kinloch is assigning far too little cost to the summer peak period.

Q. Does Mr. Baron criticize your study for assigning too little cost to the summer peak period?

A. Yes. On pages 15 and 16 of Mr. Baron's testimony he states as follows:

> Only 26% of the total production and transmission demand-related costs for either of the two operating systems are assigned based on customer class contributions to the summer peak. This is somewhat ironic, since it is the summer peak that drives the Company's planning requirements to acquire new generation capacity. (Direct Testimony of Stephen J. Baron, pp 15-16.)

If Mr. Baron is troubled that the Companies' cost of service studies allocate only 26% of fixed production costs on the basis of the summer peak, he should be absolutely stunned that Mr. Brown-Kinloch only allocates 18% on the basis of class contributions to the summer peak demand.

Q. What is your view of Mr. Baron's observation?

A. I agree with Mr. Baron that the summer peak demand drives LG&E and KU's requirements to add new generation capacity. Furthermore, summer peak demand has been the principal driver in the Companies' capacity expansion plans for quite a few years. In my view, the 26.45% of fixed production costs allocated on the basis of summer coincident peak demand is on the lower end of the range that should be considered reasonable. In my opinion, the 18.11% allocated on the basis of summer coincident peak demand in Mr. Brown-Kinloch's cost of service study is outside the range of reasonableness.

We considered an alternative method based on the Companies' resource planning models that would have allocated 71.43% of fixed production costs on the basis of summer coincident peak demands, 28.57% on the basis of winter coincident peak demands, and none on the basis of off-peak energy. These percentages were based on the number of hours of "unserved load" during each costing period. *Unserved load* is a planning measurement used to plan the Companies' generation resources. Ultimately, the BIP methodology was selected over the unserved load methodology because: (1) the BIP methodology was used in the cost of service study submitted by LG&E in its last base electric rate case, Case No. 90-158, and was found to be reasonable by the Commission in that and earlier proceedings, (2) it provides a good representation of how the generation system is utilized, and (3) it prevents any single rate class from receiving a free ride.

Q. What do you mean that the BIP methodology prevents any single rate class from receiving a free ride?

A. With some cost of service methodologies – including the single CP methodology, 12-CP methodology and the Unserved Load methodology – customer classes that are not using electric energy at the time of the utility's system peaks will not be allocated any fixed production costs. For example, lighting customers may not be using any electric energy at the time of the system peak. A methodology that allocates fixed costs on the basis of a single coincident peak would not assign any of those costs to lighting customers. Methodologies that fail to allocate any fixed production costs to certain customer classes, even though they utilized the facilities, provide those customers with a "free ride". Over the years, the Commission has expressed concerns with any methodology that fails to allocate any fixed costs to customers that have access to electric energy whenever it is demanded. For example, in its Order in Case No. 90-158, the Commission rejected a cost of service study submitted by a KIUC witness because it placed too much weight on coincident peak demand. Even though it would offer an excellent representation of how the Company's production facilities are planned, one of the principal reasons that we did not utilize the "unserved load" methodology was because it would place too much emphasis on coincident peak demands and would therefore be contrary to the clear guidance provided by the Commission.

Q. Mr. Baron presents the results of several cost of service studies as a part of his testimony. Do any of these cost of service studies allocate fixed production and transmission costs solely on the basis of coincident peak demands?

A. Yes. Mr. Baron presents the results of five cost of service methodologies in his testimony, three of which rely exclusively on coincident peak demand allocators. The summer/winter average coincident peak cost of service study, the single summer coincident peak study, and the 12-month coincident peak cost of service study allocate production and transmission fixed costs solely on the basis of coincident peak demands.

The cost of service studies summarized in Baron Exhibit ____(SJB-2) and Baron

Exhibit ____(SJB-7) are revised versions of the Companies' cost of service studies, utilizing the BIP methodology, which do not rely exclusively on coincident peak demands to allocate fixed production and transmission costs, as do the cost of service studies summarized in Baron Exhibit ____(SJB-3) and Baron Exhibit ____(SJB-8) utilizing an average and excess methodology.

Q. Mr. Brown-Kinloch claims that he used the Probability of Dispatch ("POD") methodology in the cost of service study submitted as a part of his direct testimony. Did he use the same procedures that were utilized by KU when it performed the cost of service study submitted in its last general rate case?

A. No. KU used the POD methodology in its last general rate case that was filed on September 20, 1982. Mr. Brown-Kinloch seems to believe that because it was used by KU in 1982, the POD methodology has been warranted a special status, one that might supplant the long-standing and more recent acceptance of the BIP methodology by the Commission. However, in applying the POD methodology, Mr. Brown-Kinloch used an entirely different methodology than the one utilized by KU in the cost of service study submitted in its last general rate case filed in 1982. Mr. Brown-Kinloch's heterogeneous application of the POD methodology bears little resemblance to the methodology used by KU. He either has a fundamental misunderstanding of the procedures used to perform the POD methodology or he simply ignored all of the key steps in order to make it less data intensive. The procedure he used basically has the effect of assigning the cost of generating units to the costing periods on the basis of energy. It is therefore not surprising that the amount of costs assigned to each costing period closely follows the amount of energy sold during each period.

Q. What steps did Mr. Brown-Kinloch omit?

A. He essentially ignored all of them. In its last general rate case, the following procedures were used by KU in applying the POD methodology:

1. The probability of dispatching each generating unit was calculated for typical hours in each month of the year based on hourly loads for a three-year period.
2. The probabilities of dispatch for each generating unit were then determined for each costing period.
3. The fixed costs of each generating unit were then assigned to each costing period by month based on the relative probability of dispatch during each costing period.
4. The fixed costs for each unit assigned to each costing period for each month were then allocated to the rate classes on the basis of monthly CP demands during the two peak periods (winter peak and summer peak) and on the basis of monthly average demands during the off-peak periods.

None of these steps were followed in Mr. Brown-Kinloch's cost of service study. He failed to calculate probabilities of dispatch for typical hours in each month of the year based on hourly loads for a three-year period. He failed to determine probabilities of dispatch for each generating unit for each costing period. He failed to assign fixed costs of each generating unit to each costing period by month based on the relative probability of dispatch during each costing period. He failed to allocate fixed costs for each unit assigned to each costing period for each month to the rate classes on the basis of monthly CP demands during the two peak periods (winter peak and summer peak) and on the basis of monthly average demands during the off-peak periods.

One of the fundamental differences between the POD methodology and the BIP methodology is that the POD methodology allocates costs assigned to the off-peak period on the basis of the average demand during the off-peak period. Mr. Brown-Kinloch never performs this step. In the end, he allocates all costs assigned to the off-peak period on the basis of annual energy, including energy during the off-peak period and energy during the peak periods. For all intents and purposes, Mr. Brown-Kinloch has a contrived a new methodology that benefits the residential class and then calls it the "POD Method", when in fact it bears practically no resemblance to the actual POD methodology used by KU many years ago.

Q. When did KU last use the POD methodology?

A. The last time KU submitted a cost of service study that utilized the POD methodology was in Case No. 8624 filed on September 20, 1982. The BIP methodology was used by KU when filing its unbundling studies on July 26, 2001, pursuant to Commission Orders in Case Nos. 98-474 and 2002-528. LG&E used the BIP methodology in the cost of service study that it submitted in its last base electric rate case (Case No. 90-158). In its order in Case No. 90-158, the Commission stated:

> The Commission continues to believe that the BIP method is appropriate as a means of allocating production and transmission costs to the customer classes. The BIP method recognizes that LG&E's embedded production and transmission costs were incurred to meet all customer demand, not just that which is coincident with system peak. (Order in Case No. 90-158, dated December 21, 1990, page 58.)

The Commission also approved the BIP methodology in three of LG&E's earlier rate cases, Case Nos. 8616, 8924, and 10064.[14]

Q. Did Mr. Brown-Kinloch use the POD methodology to allocate transmission costs in his cost of service studies?

A. No. He assigns transmission costs to the costing period on the basis of cumulative generation loading within each costing period. Again, this is essentially the same as assigning the costs to the costing periods on the basis of the amount of energy sold (kWhs) during each costing period.

Q. Was the methodology Mr. Brown-Kinloch used to allocate transmission costs consistent with the methodology that KU used in the cost of service study submitted in Case No. 8624?

A. No. This is yet another example of Mr. Brown-Kinloch making selective modifications to the Company's cost of service study to obtain results that promote his agenda for reducing the amount of costs allocated to the residential rate class. Although he claims to have used the POD methodology used by KU to allocate production fixed costs in the 1982 rate case, he makes no effort to apply the methodology used by KU to allocate transmission costs. He simply devises an approach that allocates a greater percentage of costs on the basis of energy (kWhs) and a smaller percentage of costs on the basis of demand (kW). He allocates 56.2358% to the off-peak period, 29.9160% to the winter peak period, and 13.8482% to the summer peak period. These percentages correspond to the ratio of the average megawatt hours of generation during each costing period for 2001, 2002, and 2003. He fails to explain why it is appropriate

14 See page 56 of the Commission's Order in Case No. 90-158 dated December 21, 1990. The Order in Case No. 8616 was issued March 2, 1983; the Order in Case No. 8924 was issued May 16, 1984; and the Order in Case No. 10064 was issued July 1, 1988.

to assign transmission costs to the costing periods on the basis of energy (kWhs). He also fails to explain why he chose not to follow any of the methods that have been approved by the Commission in prior rate cases.

In Case No. 8624, KU used Grainger's Proportional Responsibility Method to allocate transmission costs.[15] In applying the Proportional Responsibility Method, KU employed the following steps: (1) each of the 8760 hourly demands were calculated as a percentage of the annual system peak demand, (2) the lowest demand cost responsibility percentage was assigned to each hour in which a load of at least this level occurred, (3) the difference between the lowest and the i^{th} lowest demand cost responsibility (i.e. the second lowest, third lowest, fourth lowest, et seq.) was then spread over each hour in which a load greater than or equal to this level had occurred, and (4) the allocated demand cost responsibilities for each hour were then summed to determine the proportional responsibility within each costing period.[16] Mr. Brown-Kinloch failed to follow any of these steps in developing his transmission allocation scheme.

Q. Did Mr. Brown-Kinloch make any other minor changes to LG&E and KU's cost of service studies?

A. Yes. He made several minor modifications, some of which I agree with. First, Mr. Brown-Kinloch modified the way that demand-related purchased power costs were functionally assigned in the cost of service study. In the Companies' cost of service studies, these costs were assigned exclusively to the peak period. This was an oversight on our part, and we agree with Mr. Kinloch on this issue. Demand-related purchased power costs should have been

15 Granger's Proportionality Method was described in Grainger, Gary H., "The Proportional Responsibility Method of Capacity Cost Allocation," *Public Utilities Fortnightly*, November 9, 1972, pp. 25-30.
16 See pp. 16-18 of the Testimony and Exhibits of Ronald Wilhite, dated September 20, 1982, in Case No. 8624.

assigned to the costing periods on the same basis as fixed production costs, using the BIP percentages. This modification has been made to the updated cost of service studies included in Seelye Rebuttal Exhibit 4 for LG&E and in Seelye Rebuttal Exhibit 5 for KU.

Second, Mr. Brown-Kinloch points out an inconsistency in the way that operation and maintenance expenses and labor expenses were classified for Accounts 512, 513, and 514. In the section of the study dealing with operation and maintenance expenses these accounts were classified as fixed costs, and in the section of the study dealing with labor expenses these accounts were classified as energy costs. I am in agreement with Mr. Brown-Kinloch on this issue. The operations and maintenance expenses for these accounts should have been classified as energy-related. This modification has been made to the updated cost of service studies included in Seelye Rebuttal Exhibit 4 for LG&E and in Seelye Rebuttal Exhibit 5 for KU.

Third, Mr. Brown-Kinloch made a modification to the methodology used to classify materials and supplies. He maintains that "these are the cost of storing fuel and reactant" and should be classified as energy-related. I disagree with Mr. Kinloch on this modification. Contrary to his claim, materials and supplies include items other than the cost of storing fuel and reactant. In addition to fuel and reactant inventories, materials and supplies include replacement parts and other plant items. These costs should be classified on the same basis as plant. Furthermore, LG&E and KU maintain fuel and reactant inventories to meet demand requirements. Hypothetically, if demand variability and peak load requirements were eliminated, utilities could move even closer to "just-in-time" procurement strategies for fuel and reactant supplies, thus reducing or even eliminating the need to carry inventories on these items. If it were not for demand variability and peak load requirements, the utility would not require the level of fuel and reactant inventories that are maintained. Consequently, it is reasonable to classify fuel and reactant inventories on the same basis as plant.

Fourth, Mr. Kinloch modified the allocator used for "Brokered Sales" in the cost of service study. Specifically, he modified the allocator from "Energy" to "PLPPT" for three items in the cost of service study: (1) the brokered sales identified under operating revenues, (2) the pro-forma revenue adjustment for brokered sales, and (3) the pro-forma expense adjustment for brokered sales. He failed, however, to modify the functional vector used for the purchased power expenses related to brokered sales so that they would also be allocated on the basis of "PLPPT". In the Companies' cost of service studies, these expenses were classified as energy-related in the "OMPP" functional vector and allocated on the basis of "Energy" in the cost of service study. Had he also changed the "OMPP" so that the purchased power expenses related to brokered sales were classified as "Production Demand", Mr. Brown-Kinloch would have found that his proposed use of "PLTT" instead of "Energy" as an allocator would not have had any impact on the cost of service study. As was explained in the LG&E's response to AG 2-23, "[a]s long as a consistent allocator is used for brokered sales, expenses, revenues, and the pro-forma adjustment, it does not matter which allocator is used." Mr. Brown-Kinloch failed to use consistent allocators for all of these items; specifically, he failed to modify the allocator used for purchased power expenses. As a consequence, his results are improperly skewed in favor of rate classes with lower relative load factors.

Fifth, Mr. Brown-Kinloch changes the allocator used to allocate the off-system sales revenue adjustment for the ECR calculation from "PLPPT" to "OSSALL". Because the margins on off-system sales are allocated on the basis of production rate base, this modification has practically no effect on the cost of service studies. We have no fundamental problem with Mr. Brown-Kinloch's approach and can accept his proposed modification. Although the impact is almost imperceptible, this modification has been made to the updated cost of service studies included in Seelye Rebuttal Exhibit 4 for LG&E and in Seelye Rebuttal Exhibit 5 for KU.

Sixth, Mr. Brown-Kinloch changes the allocator used for the adjustment for merger savings and the adjustment for merger amortization expenses from a total labor allocator to a revenue allocator. Although hardly worth arguing about, we disagree with this adjustment. Mr. Brown-Kinloch reasons that since the revenue adjustment for the merger savings was allocated on the basis of revenue, then the adjustment to expenses should be allocated on the same basis. His logic is flawed. The reason that the revenue adjustment was allocated on the basis of revenue was that customers receive the credit based on a percentage of revenues. On the other hand, the reason the Companies' merger-related expense adjustments were allocated on the basis of labor was that labor savings comprised the principal component of all merger savings. The fact that merger credits are assessed on the basis of revenue does not imply that the costs associated with the credits should be allocated on the basis of revenue. The revenue credit mechanism has no bearing on how the costs are incurred. According to this upside-down logic, costs should be allocated on the basis of the rates charged rather than determining rates on the basis of costs. Mr. Brown-Kinloch applies the same methodology to the VDT adjustments. Although the impacts of these changes are small, we cannot accept Mr. Brown-Kinloch's proposed changes.

Seventh, Mr. Brown-Kinloch modified the allocator used to distribute revenue from intercompany sales. He proposes to allocate these revenues on the same basis as off-system sales margins. Mr. Brown-Kinloch has again made selective changes without making corresponding changes to expenses. These "revenues", which are a part of the economic dispatch and transfer cost mechanism for LG&E and KU, relate to purchased power and fuel that is purchased by one utility (either LG&E or KU) and transferred to the other utility. His reference to revenues from intercompany sales as "profits" is inaccurate and misleading. Unlike revenues from off-system sales, there are no net margins from making these transactions. Any "margins" received by LG&E from KU (or vice versa) are immediately returned to LG&E's customers through the fuel adjustment clause. Because the fuel and purchased power expenses are recorded as energy-related expenses and are recovered through the fuel adjustment clause of both utilities, it is appropriate and consistent to allocate these "revenues" on the basis of energy. Accordingly, we cannot accept this modification.

Q. What changes did Mr. Baron make to the Company's cost of service study?

A. As mentioned earlier, Mr. Baron performed several alternative cost of service studies. However, he relied on a modified version of the Company's BIP cost of service study to develop his recommendations regarding the allocation of the revenue increase to the rate classes. Mr. Baron made three modifications to LG&E's cost of service study. First, he made an adjustment to reflect the removal of ECR related plant from rate base. We have no objection to this modification, and have incorporated the change in the updated cost of service studies included in Seelye Rebuttal Exhibit 4 for LG&E and in Seelye Rebuttal Exhibit 5 for KU.

Second, he made an adjustment to reflect the revised avoided cost revenues for the Curtailable Service Rider ("CSR") in the determination of the adjusted actual rates of return. This modification is purely academic, and does not have any impact on the proposed rates of return shown in the Companies' cost of service studies. We incorporated the revised avoided cost revenues in calculating the proposed rates of return, rather than the adjusted actual rates of return. The methodology used in the Companies' cost of service studies is more appropriate because the revised avoided cost revenues were not included as pro-forma adjustments as Mr. Baron shows them in his cost of service studies. Therefore, we cannot accept this modification.

Third, Mr. Baron made an adjustment to allocate the CSR related expenses to the customer classes on the basis of summer peaking costs, rather than the BIP allocator. We agree that CSR related expenses should not be assigned on the basis of the BIP allocator because interruptible service is not needed during the off-peak period. The Companies do not just interrupt CSR service during the summer peak period. Interruptible service is frequently used during the winter peak period as well. Accordingly, we have allocated the CSR related expenses to the customer classes on the basis of summer and winter peaking costs in the updated cost of service studies included in Seelye Rebuttal Exhibit 4 for LG&E and in Seelye Rebuttal Exhibit 5 for KU.

Fourth, Mr. Baron pointed out data problems in the development of the demand allocators for the all-electric schools, Rate 33, and HLF classes for the KU cost of service study. These data errors have been corrected in the updated cost of service studies included in Seelye Rebuttal Exhibit 5.

Q. What impact do the corrections that were made to the Companies' cost of service studies have on the class rates of return?

A. All of the adjustments proposed by Mr. Baron benefited high-load factor customers, while the items accepted from Mr. Brown-Kinloch's proposed changes helped low-load factor customers.

Hence, the modifications with which we agreed offset one another to some extent. The following table compares the class rates of return from the LG&E's original cost of service study to the class rates of return from the updated cost of service study:

Louisville Gas and Electric Company Electric Class Rates of Return Original vs. Updated Cost of Service Study		
Customer Class	**Original Adjusted Rate of Return**	**Updated Adjusted Rate of Return**
Residential Rate R	1.51%	1.90%
General Service Rate GS	8.55%	9.73%
Large Commercial – Rate LC		
- Primary	6.81%	7.65%
- Secondary	6.66%	7.68%
Industrial Power – Rate LP		
- Primary	5.48%	6.10%
- Secondary	8.26%	9.26%
Large Commercial Time of Day – Rate LC-TOD		
- Primary	5.92%	6.62%
- Secondary	5.95%	6.85%
Industrial Power Time of Day – Rate LP-TOD		
- Transmission	5.38%	5.71%
- Primary	3.79%	3.94%
- Secondary	6.58%	7.40%
Special Contracts	5.33%	5.81%
Lighting	3.56%	3.35%
Total System	4.06%	4.61%[17]

As can be seen from this table, the class rates of return did not change significantly from LG&E's original electric cost of service study.

17 The overall rate of return changed because ECR plant was removed from rate base, thus changing the divisor in the rate of return calculation.

The following table compares the class rates of return from the KU's original cost of service study to the class rates of return from the updated cost of service study:

Kentucky Utilities Company Electric Class Rates of Return Original vs. Updated Cost of Service Study		
Customer Class	**Original Adjusted Rate of Return**	**Updated Adjusted Rate of Return**
Residential	0.44%	0.59%
General Service Rate	5.66%	6.53%
Large Power (LP & HLF)	8.06%	9.05%
Large Power TOD	7.08%	7.66%
Coal Mining Power	11.19%	12.45%
Coal Mining TOD	8.77%	9.71%
Special Contracts	9.35%	11.36%
Lighting	2.84%	2.66%
Total System	3.93%	4.32%[18]

Again, the class rates of return did not change significantly from the KU's original electric cost of service study.

IV. Allocation of Electric Rate Increase

Q. Intervenor witnesses representing large industrial and commercial customers express concerns about the amount of rate increase allocated to their clients. What is the basis of their concerns?

A. KIUC witness Baron, Kroger witness Higgins, and Department of Defense witness Kincel are

18 The overall rate of return changed because ECR plant was removed from rate base, thus changing the divisor in the rate of return calculation.

critical of the Companies' proposed allocation of the rate increase to the classes of customers. They essentially argue that the increase allocated to large industrial customers, large commercial customers, and special contracts do not reflect the results of the Companies' cost of service study. Their argument is valid. Ideally, we would have preferred to follow the results of the cost of service study; however, LG&E and KU had serious concerns about the level of increase to certain rate classes – specifically the residential and lighting classes – required to eliminate, or even to reduce significantly, the subsidy to these two rate classes. It should be noted that Attorney General witness Brown-Kinloch agreed with the Companies' proposal to limit the increase to the residential classes.[19] Even if Mr. Brown-Kinloch's cost of service study were used to design rates, the increase to the residential class would have been 22.52%[20] for LG&E and 20.17%[21] for KU.

Q. Testifying on behalf of a group of large industrial customers, KIUC witness Baron proposes to decrease inter-class rate subsidies by 25%. Please comment on his recommendation.

A. On pages 38 through 47 of his direct testimony, Mr. Baron recommends a methodology for allocating the rate increase to the customer classes that would eliminate 25% of the subsidies to each class. In calculating the level of the subsidies, he relied on the Companies' cost of service methodology although he expressed concerns about the approach. Mr. Baron also discusses the importance to economic development in maintaining low rates to commercial and industrial customers in Kentucky. Specifically, he refers to a White Paper issued by the Kentucky

19 Testimony of David H. Brown Kinloch, page 28.
20 Testimony of David H. Brown Kinloch, Exhibit DHBK-9, page 52 of 63.
21 Calculated from the results of Mr. Brown-Kinloch's cost of service study.

Cabinet for Economic Development addressing the importance of low energy rates in attracting and retaining industry in Kentucky. Kroger witness Higgins recommends a similar methodology for eliminating inter-class rate subsidies. On page 20 of his testimony, he states that, "payment of subsidies can inefficiently influence behavior by distorting location and investment decisions."

There is nothing fundamentally wrong with trying to eliminate 25% or more of the current rate subsidies, except for the level of the increase to residential and lighting customers necessary to achieve this result. In my opinion, Mr. Baron's proposal is consistent with the principle of gradualism, and is not unlike some of the methodologies for allocating the increase considered, but ultimately rejected, by the Companies. Mr. Baron's proposal would result in a residential increase of 17.7%[22] for LG&E and 15.31%[23] for KU. The Companies believed residential increases of these magnitudes were unacceptable, and decided to cap the LG&E increase at approximately 12% and the KU increase at approximately 10%, which were about 1% above the overall increases for the two utilities. In addition to gradualism, the Companies were also concerned with the principles of *rate continuity* and *customer acceptance*.

Q. Is there any significance to the 1 percentage point cap above the overall increase?

A. Not really. The 1 percentage point cap was selected when we realized that the overall increase was likely to be above 10%. Had the overall increases been lower, then the Companies would have tried to eliminate more of the rate subsidies among the customer classes.

22 Direct Testimony and Exhibits of Stephen J. Baron, page 45.
23 Direct Testimony and Exhibits of Stephen J. Baron, page 44 and Exhibit___(SJB-12).

Q. Are you suggesting that if the Commission lowers the revenue increase from the levels proposed by the Companies then more of the inter-class subsidies should be eliminated?

A. First, I want to make it clear that I am in no way suggesting that the rate increase should be lower than what was proposed by the Companies. On the contrary, I can positively say that the rate increases proposed by LG&E and KU are reasonable. With that caveat, I feel comfortable in saying that should the Commission grant a lower rate increase then every effort should be made to eliminate more of the inter-class subsidies, up to or even exceeding the level of mitigation recommended by Mr. Baron. As already mentioned, eliminating 25% -- or even 50% -- of the current subsidies recognizes the principle of gradualism. The Companies' principal consideration in capping the increase to the residential class was to avoid rate shock, and by limiting the LG&E increase to approximately 12% and the KU increase to approximately 10% this objective has already been accomplished. Therefore, if the rate increases allowed by the Commission are lower than what were proposed by the Companies – and, again, I am not recommending that they be lowered – then the cap of 1 percentage point above the overall increase for the residential and lighting classes should not be strictly followed. In other words, the Companies have no objection to Mr. Baron's recommendation as long as it does not result in an increase greater than 12% for residential or street lighting rate classes as proposed by LG&E, or 10% for residential or street lighting rate classes as proposed by KU.

Q. Representing the Department of Defense, Mr. Kincel recommends that all special electric contract customers be assigned the same increase. Do you agree with this recommendation?

A. No. Mr. Kincel is arguing on behalf of Fort Knox, which is one of five electric special contract customers served by LG&E. LG&E is proposing to increase Fort Knox's electric rate by 12.3%, compared to 10.6% to the other special contract customers. The proposed rate increases for the special contract customers were based on rates of return determined by further sub-dividing and allocating costs to the individual special contract customers. Because it is LG&E's practice, in recognition of the customers' private business information, not to divulge individual customer information in rate case filings, the results for individual special contract customers were not displayed in cost of service study exhibits included in my testimony. Mr. Kincel makes the argument that since LG&E only provided cost of service results for the special contract customers in aggregate, all of the special contract customers should be assigned the same rate increase.[24] In response to Mr. Kincel's argument, the following table is provided to show the rates of return for LG&E's special contract customers from LG&E's updated cost of service study:

24 Direct Testimony of Kenneth L. Kincel, pages 20-21. Although the Company did not provide cost of service results for individual special contract customers, Mr. Kincel could have performed his own analysis (since demand and energy data for Fort Knox would have been available to him through his client), or the Department of Defense could have submitted data requests seeking the necessary information to evaluate the reasonableness of the Company's proposal. LG&E did not receive any data requests from the Department of Defense.

Special Contract Customer	Rate of Return
Special Contract Customer	3.43%
Fort Knox	3.99%
Special Contract Customer	7.18%
Special Contract Customer	9.25%
Special Contract Customer	10.21%

As can be seen from this table, the rate of return for Fort Knox is significantly lower than most of the other special contract customers, thus supporting a larger increase for Fort Knox.

Q. Mr. Baron expresses concerns about the proposed increase to MeadWestvaco. What are his concerns as you understand them?

A. Mr. Baron objects to KU's proposed increase to MeadWestvaco by an amount greater than KU's proposal for the LCI-TOD class.

Q. Please describe the MeadWestvaco contract.

A. The contract was first executed in April 1968. The contract had a contract capacity of 25,000 kVa and a firm demand of 10,000 kVa with a provision for curtailable load in excess of the 10,000 kva. The contract was later amended in February 1989 when Westvaco added a new paper machine at the Wickliffe operation. At that time, the then current kVa charges were converted to a per kW charge based on Westvaco's power factor. This per unit conversion permitted separation of the existing and future load for billing under special contract charges and LCI-TOD charges respectively. The load being served under the special contract had grown to 33,250 kW (35,000 kva @ 95 % PF) since 1968. The new paper machine load was 16,150 kW and served pursuant to a separate LCI-TOD contract executed concurrently with the amended special contract. The amended special contract retained the rate structure for the existing load, while the new load was billed on KU's then applicable LCI-TOD rate. The LCI-

TOD contract was later amended in September 1997 to increase the contract capacity for LCI-TOD billing by 7,550 kW to facilitate the addition of a carbon plant by Westvaco.

Q. Why were the additional loads in 1987 and 1997 not served under a further amended special contract?

A. As it turned out Westvaco's original load could not be interrupted with the exception of some sewer pumps and other minor load equipment. Therefore, it was appropriate to place any new load on the existing applicable class tariff, which was the LCI-TOD schedule.

Q. Do you agree with Mr. Baron's contention that there is a special contract class?

A. Absolutely not. It is the Companies' practice not to reveal information on individual customers in the cost of service study, in recognition of the proprietary business information of the customers. We therefore combined KU's two special contract customers for that purpose only. KU in no way meant to imply that somehow there is a "special contract" rate class. Each individual KU special contract represents a rate class pursuant to KRS 278.030. In fact, KU's Tariff has never identified a rate class for a group of special contracts. KU has never had at any one time more than two special contracts in existence and those contracts were for customers whose operational characteristics were significantly different from each other and from existing rate classes when the contracts were executed.

Q. What is the rate of return for MeadWestvaco in KU's cost of service study?

A. The updated cost of service study for KU indicates that the rate of return for MeadWestvaco is 4.42%. This would suggest that MeadWestvaco should receive an increase at least as large as the overall increase.

Q. Do you agree with Mr. Baron that KU's proposed increase for the MeadWestvaco

special contract charges effectively negate the value of the contract?

A. No. MeadWestvaco has not been able to provide the amount of curtailable load as originally contemplated in 1968. Its load is similar in characteristics to customers served on the LCI-TOD rate. Therefore, to increase the special contract charges as I have recommended would gradually move the special contract toward the LCI-TOD charges.

Q. Mr. Baron complains that MeadWestvaco is too large to be served under Schedule LCI-TOD. Would KU have any objections to serving MeadWestvaco's entire load under a rate schedule similar to LCI-TOD?

A. No. Although MeadWestvaco's load is greater than the 50,000 kW limit for LCI-TOD, because the customer has load characteristics similar to other customers served on LCI-TOD, KU would be willing to serve MeadWestvaco under a rate schedule fashioned after LCI-TOD.

V. Electric Rate Design

(a) Residential Rate Design

Q. What changes does LG&E propose to its residential rate design?

A. We propose to eliminate the winter declining block rate and the summer inverted block rate, and to increase the customer charge from $3.31 to $9.00 per customer per month. The increase in the customer charge is significantly less than the $13.49 per customer that can be supported from the cost of service study.

Q. What changes does KU propose to its residential rate design?

A. We propose to eliminate the declining block rate structure, and to increase the customer charge from $2.82 to $9.00 per customer per month. A customer charge of $14.21 can be supported from the cost of service study. KU is also proposing to consolidate its residential all-electric rate (Schedule FERS) with the standard residential service.

Q. What changes does Attorney General witness Brown-Kinloch recommend?

A. Mr. Brown-Kinloch recommends eliminating the winter declining block and summer inverted block rate structure for LG&E, and the declining block structure for KU. Mr. Brown-Kinloch does not object to merging KU's Shedule RS with FERS. He proposes lower customer charges than recommended by the Companies. Surprisingly, Mr. Brown-Kinloch recommends eliminating LG&E's summer/winter differential.

Q. Why are you surprised by Mr. Brown-Kinloch's proposal to eliminate the summer/winter rate differential?

A. As mentioned earlier in my testimony, LG&E is a strongly summer peaking utility. The summer peak is the driving force behind the Company's need to add generation capacity, and has been the key driver in its generation expansion plans for many years. One of the major flaws with Mr. Brown-Kinloch's cost of service study is that the methodology he uses to allocate production costs does not recognize this fact. He assigns essentially the same cost per kWh to the summer peak period as he does to the winter peak period and to the off-peak period. This underscores a serious flaw in his cost of service methodology. One could assume that Mr. Kinloch recommends eliminating LG&E's seasonal rate structure because his defective cost of service study suggests that there is no difference in costs between the summer months and winter months. However, this does not explain the fact that Mr. Brown-Kinloch proposes to retain the seasonal rate structure for general service customers (Rate GS). Mr. Brown-

Kinloch's cost of service study does not support a seasonal rate structure for Rate GS any more than it does for Rate R.

Q. Is there any justification for Mr. Brown-Kinloch's proposed customer charges?

A. None whatsoever. In developing the "cost support" for his proposed customer charge, Mr. Brown-Kinloch disregarded the results of his own cost of service study. For example, in his cost of service studies, he classifies a portion of transformers, overhead conductor, underground conductor, and distribution services as customer-related and allocates those costs on the basis of the number of customers within each rate class. However, in computing costs to be recovered through the customer charges, Mr. Brown-Kinloch ignores that he classified these costs as customer-related in his cost of service study. This error in logic results in a reassignment of customer-related costs to the energy component of the rate. He thus develops an attenuated customer charge that ignores – and in effect nullifies – the zero-intercept methodology used to classify customer-related costs accepted by the Commission. Mr. Brown-Kinloch is undermining the use of the zero-intercept methodology in designing rates by arguing that the customer-related costs identified through the zero-intercept methodology are not really *customer-related* costs but are in fact *energy-related* costs to be recovered through the energy charge. This breakdown in logic is the consequence of his trying to fabricate a particular set of results that are more suitable to his agenda.

Q. How did the Commission respond to Mr. Brown-Kinloch's recommended customer charge, which ignored costs classified as customer-related, in LG&E's last base gas rate case?

A. In Case No. 2000-080, Mr. Brown-Kinloch used the same faulty approach for calculating customer costs to be recovered through the customer charge, and the Commission rejected his recommendation. In that proceeding, Mr. Brown-Kinloch recommended a $4.48 customer charge, but the Commission accepted the $7.00 customer charge proposed by the Company.[25] The Commission specifically rejected limiting the customer-related costs to be recovered through the customer charge in the manner recommended by Mr. Brown-Kinloch.[26]

Q. What type of rate design does Kentucky Division of Energy witness Young recommend?

A. Mr. Young approves of the elimination of declining block rates and he approves of LG&E's seasonally differentiated rate. However, he recommends that the Companies "design and institute inclining block rates in this rate case to provide an economic incentive for customers to reduce energy waste." An inverted block rate would charge customers that use more energy a higher rate than customers that use less energy. Mr. Young recommends that the monthly customer charge either remain unchanged or decrease. Additionally, he recommends that the Companies provide an optional real-time pricing or time-of-use rate, enhance its portfolio of demand-side management programs, and implement a decoupling mechanism.[27]

Q. Do you have any comments about Mr. Young's recommendation for an inverted block rate?

A. Yes. Mr. Young has not put forward an actionable proposal. He offers no specific rate design. Without specifics it is difficult to evaluate what he has in mind regarding the implementation

25 In Case No. 2000-080, LG&E proposed a three year phase-in to move the customer charge to a cost-based rate. In its Order in Case No. 2000-080, the Commission accepted the customer charge that the Company proposed in the first year of the three-year phase in.

26 On pages 75-76 of its Order in Case No. 2000-080, dated September 27, 2000, the Commission indicated that, "[Mr. Brown-Kinloch's] modified cost of service study, when presented in a manner similar to LG&E's cost of

of an inverted block rate. Furthermore, he fails to provide any cost support that would justify an inverted block rate. LG&E and KU supplied a detailed statistical analysis showing that there is no cost basis for an inverted block rate. Without refuting the Companies' analysis or supplying an analysis of his own he simply waves off LG&E and KU's detailed statistical studies by making the tautological claim that "the relationships [Mr. Seelye] identifies are weak and tenuous".[28] The statistical analysis referenced by Mr. Young examined the relationship between customer usage and key allocators used in the Companies' cost of service studies – namely, summer coincident peak demands, winter coincident peak demands, and non-coincident peak demands. The purpose of this statistical analysis was to determine whether there is a relationship between customer load factor and usage that could support an inverted block rate structure. The analysis indicated that no such relationship exists. For this very reason an inverted block rate structure cannot be supported, contrary to Mr. Young's assertion.

All that Mr. Young offers in support of an inverted block rate is a single statement that, "Inclining block rates are appropriate when a utility faces marginal production costs that are higher than average embedded costs, which is the case for LG&E and much of this country's utility industry today." Besides being flat wrong about higher marginal costs supporting inverted block rates, Mr. Young has not substantiated his claim that the Companies' marginal costs are in fact higher than its embedded costs. Although I have not analyzed the Company's marginal electric costs in a number of years, I doubt that there is much difference between marginal and embedded electric costs (especially between marginal and embedded *production*

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service study, indicates the residential customer charge should be significantly increased."

27 Testimony of Geoffrey M. Young, pages 12 and 18.

28 *Ibid.*, page 17.

costs). But even if marginal costs were higher than embedded costs, he would still have to demonstrate that the *cost per kWh* increases as individual customers use more kWh. The principal drivers in LG&E's and KU's marginal costs are the same as in their embedded costs – namely changes in coincident peak demand, changes in the number of customers, and changes in energy. To be convincing, Mr. Young would have to support his claim that costs per kWh are proportional to increased customer usage in the same way that the Companies have analyzed the issue – with a statistical analysis examining the relationship between key cost drivers and customer usage.

Q. Do you have any comments about Mr. Young's recommendation concerning the customer charges?

A. Yes. Mr. Young proposes that the Commission not change the customer charges, either by increasing or decreasing them. Again, he offers no cost support for his proposal. His recommendation, which runs contrary to trends in the industry, is based on theoretical ruminations and misguided assumptions rather than on any sort of analysis. For example, he claims that, "On average, low-income customers tend to use less energy."[29] The Companies' experience has been that low-income customers use about the same amount of electric energy as the average customer and they purchase somewhat more natural gas than the average customer. In fact, most of LG&E and KU's customers fall within a fairly tight band around the average. Low income customers purchase electric energy and gas for the same reasons that most other customers purchase energy – to heat and cool their homes, to cook, and for refrigeration, lighting and other small appliances. For this reason, the energy profiles for low-

29 *Ibid.*, page 13.

income customers are not significantly different from typical residential customers. The residential accounts that generally see larger percentage impacts from increasing the customer charge are workshops, barns, vacation homes, hunting shacks, and outbuildings. Although these types of customers generally use very little electric energy, to serve these customers the utility must make a line extension, install a transformer, install a service line, install a meter, and then the utility must read the meter and process a bill each month. Unless the customer charge is set at a level that reflects the cost of providing service, the revenue received from these customers never comes close to covering the fixed costs incurred in providing service to them. I work with utilities all over the country, and it has been my experience that these types of customers are the ones that tend to voice concerns about increasing the customer charge.

Q. Do you have any comments about Mr. Young's recommendation for LG&E and KU to implement an optional real-time pricing or time-of-use rate, enhance its demand-side management programs, and implement a decoupling mechanism?

A. Yes. The proper forum for evaluating these ideas is LG&E and KU's demand-side management program. Residential real-time pricing seems to have been successful with some utilities, especially those with higher rates than KU and LG&E. However, I am skeptical that a residential real-time pricing program can work with low-cost utilities such as LG&E and KU until the price of the metering equipment comes down. Residential time-of-use rates have not gained wide customer acceptance around the country. LG&E had an experimental decoupling mechanism for approximately four years, until it was terminated on May 31, 1998.[30] LG&E's decoupling mechanism was introduced as a part of a demand-side management program, which is still the appropriate forum for exploring such ideas.

(b) General Service Rate Design

Q. Does Mr. Brown-Kinloch's make any recommendations regarding LG&E's general service rate?

A. Yes. Mr. Brown-Kinloch recommends the same basic rate design as LG&E. Specifically, he proposes to retain the summer/winter differential in the energy charge but he proposes a lower customer charge than LG&E. Mr. Brown-Kinloch also fulminates against current provisions in Rate GS that limit size of a customer to 200 kW.[31]

Q. Do you have any comments about his recommendations?

A. Yes. As mentioned earlier, it is inconsistent to propose to eliminate the seasonal rate structure for Rate R but retain it for Rate GS. I believe that the seasonal structure should be retained for both rates. As already mentioned, the methodology that he uses to derive the customer charge is illogical and inconsistent with his own cost of service study. He is recovering large amounts of costs classified as customer-related in the cost of service study through the energy component of the rate.

Q. What about Mr. Brown-Kinloch's recommendation to raise the maximum size for Rate GS customers from 200 kW to 5,000 kW?

A. Mr. Brown-Kinloch's proposal to raise the maximum size of a general service customer from 200 kW (LG&E's current maximum) to 5,000 kW (KU's maximum) is misguided. In support

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30 An experimental decoupling mechanism for LG&E's residential gas and electric customers was approved in Case No. 93-150. It was withdrawn by the Company in a letter filed May 20, 1998.

31 KU is lowering the limit from 5,000 kW to 200 kW to conform with LG&E's maximum, thus drawing Mr.

of his proposal, Mr. Brown-Kinloch states:

> Currently, LG&E limits customer size [for Rate GS customers] to 200 KW, and KU limits customer size to 5,000 KW. The LG&E proposal is to set the upper limit for both Companies at 200 KW, the current LG&E limit. *The GS class is a haven for low load factor customers.* The higher rates charged in this class is a testament to that fact. Setting the combined Company limit so low will remove this valuable option from many customers. (Testimony David Brown Kinloch, pages 31-32. Emphasis supplied.)

I am puzzled about why LG&E – or Mr. Brown-Kinloch for that matter – would want to create a "haven for low load factor customers." Low-load factor customers impose a higher cost per kWh on the system than high-load-factor customers. A sound rate design should reflect the demand-, customer-, and energy-related costs of providing service to customers. Creating "havens" for high-cost customers so that they can realize a lower rate by shifting costs to other customers is unsound ratemaking.

The trend in the industry is to bill more customers under demand-metered rates, not to create sanctuaries for low-load-factor customers so that they can shift costs to other customers. A three-part rate consisting of a demand charge, customer charge and energy charge does a better job reflecting the cost of providing service than a two-part rate consisting of only a customer-charge and energy charge. The use of three-part rates helps eliminate intra-class subsidies, whereas Mr. Brown-Kinloch's proposal would help perpetuate intra-class subsidies by expanding the availability of Rate GS which consists of a two-part rate. Customers should pay the cost of service irrespective of whether they can do anything about improving their load patterns. Mr. Brown-Kinloch provides an example of a low-load factor manufacturing

Brown-Kinloch's attention.

company for which he conducted an energy audit. The manufacturing company operated one shift and was almost certainly operating at the time of LG&E's peak. Mr. Brown-Kinloch seems not to understand that a low-load factor customer that operates relatively few hours per week and places a demand on the utility system at the time of its peak *should* pay more per kWh than a high-load factor customer that operates around the clock, regardless of whether the low-load factor customer can become a high-load factor customer or not. Yet, if the customers could have the option of an energy-only rate, and avoid demand charges – as Mr. Brown-Kinloch proposes – then why would they ever change the way they operate?

(c) Large Commercial and Industrial Rate Design

Q. What was the intervenor reaction to the rate design changes to the large commercial and industrial rates?

A. They were generally favorable. KIUC witness Baron and Kroger witness Higgins support the Company's proposal to recover more of the fixed demand-related costs through the demand charge. Mr. Brown-Kinloch was silent on the large commercial and industrial rate design. Mr. Young suggested greater use of real-time pricing. The most significant concern was the objection raised by Mr. Higgins concerning LG&E's proposed modification to LC-TOD and LP-TOD raising the eligibility for prospective customers to 2,000 kW.

Q. Why did LG&E propose to raise the eligibility for the time-of-day rates to 2,000 kW?

A. The principal reason for placing the lower limit on LC-TOD and LP-TOD at 2,000 kW was to group large customers under a single rate schedule so that rates for these customers, who are generally more homogenous with respect to their load profiles, can be designed to more accurately reflect the cost of providing service. However, we recognize that such efforts must be balanced against providing customers greater choice in the services available to them.

VI. Curtailable Service Rider

Q. Please describe the purpose of the Companies' Curtailable Service Rider and the proposed changes in the tariff.

A. The Curtailable Service Rider ("CSR") is an option available to customers with a load greater than 1,000 kW that could be curtailed or interrupted within a short period of time. For customers that are truly capable of interrupting their load, CSR represents a valuable option for them to save money on their power bills and for the utility to avoid adding generation capacity. Because curtailable capacity is not included in the Companies' integrated resource plans, savings to LG&E and KU are primarily realized by avoiding the fixed costs associated with the addition of new generating units.

The Companies have proposed several changes to their existing tariffs. LG&E and KU are proposing to increase the credit for curtailable service (i.e., the credit that the customer sees on its bill for interruptible load) to $4.05 per kW at primary voltage and to $3.98 per kW at transmission voltage. This represents an increase in the credit of approximately 22.7% for primary voltage customers and approximately 20.6% for transmission voltage customers. The increase in the credit was not so much as result of increases in the Companies' avoided costs but a change in the philosophy regarding the computation and sharing of the savings. In the past, the credit for Kentucky Utilities was based on a 33/66 percent sharing of the avoided cost between the utility and the curtailable customers.[32] Since we were proposing to increase the annual hours of interruption to 500 hour in order to reflect the anticipated running time of new large-frame combustion turbines, the Companies felt that it would be appropriate to provide the customers with more (but still not all) of the savings.

Q. KIUC witness Baron recommends that the notice period for interruption be increased from 10 minutes to 1 hour. Do you have any comments about his recommendation?

A. Yes. The 10-minute notice is the notice period currently specified in LG&E's tariff. The large industrial customers currently taking service under LG&E's interruptible service rider obviously did not have a serious problem with the 10-minute notice requirement when they signed up for service under the rider. Mr. Baron complains that the combustion turbines, upon which the curtailable credit is based, cannot startup in 10 minutes unless they are already running. This is incorrect. The Companies operate seven of their jointly dispatched units in a mode that will allow them to startup from a cold-start in 10 minutes or less. These combustion turbines are a better proxy for the "avoided" cost at issue, as any new combustion turbine would be expected to be or could easily be converted to a quick-start unit. Furthermore, every one of the Companies' combustion turbines can be started within 30 minutes, so Mr. Baron's testimony makes a proposal that has no relationship to any actual units. In my opinion, the 10-minute notice requirement in the CSR tariff reflects comparability to an avoided combustion turbine, including the seven quick-start units already owned by the Companies. Furthermore, the 10-minute notice provision of the tariff allows curtailable service load to be included in

32 For LG&E the credit was not based on a 33/66 percent sharing; however, a more conservative methodology was used to determine the avoided fixed costs (LG&E used a perturbation approach). In this proceeding, we followed the Kentucky Utilities methodology for computing the savings, except that the 33/66 percent sharing percentage was not

ECAR's supplemental reserve requirements along with these combustion turbines. To be counted toward the ECAR's supplemental reserve requirements, interruptible load must be interruptible within 10 minutes. KU's notice requirement has likewise been established at 10 minutes.

Q. Mr. Baron recommends lowering the annual hours of interruption to 175 hours. Do you agree with his proposal?

A. No. The annual hours of interruption currently specified in LG&E's interruptible tariff is 250 hours and ranges from 75 to 200 hours in KU's tariff. Mr. Baron is proposing to decrease the annual hours of interruption to 175 hours, while at the same time receiving a much larger credit. The curtailable credit was based on the avoided cost of a new combustion turbine. Therefore, in developing the annual hours of interruption we examined the number of hours that a new combustion turbine would likely operate in the future. The Companies' production modeling runs indicated that by the year 2005 two of the ***newest*** large-frame combustion turbines (Brown 6 and 7) would operate between 459 and 575 hours per year. By the year 2008, the four new combustion turbines that can be operated without restrictions (Brown 6 and 7 and Trimble 5 and 6) are anticipated to run between 503 to 945 hours. The Companies' proposed annual hours of interruption were developed by analyzing the anticipated hours of operation of these combustion turbines, which was also the basis of the avoided cost.

In developing his proposed annual hours of interruption, Mr. Baron analyzed the operation of all of the Companies' combustion turbines, some of which have been in service for many years and thus are not at all representative of the expected operation of a new, avoided

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applied.

combustion turbine. Mr. Baron also chose to analyze the test year and the calendar year 2004 which are not representative because of the amount of additional capacity recently added. If he had examined calendar year 2002 he would have found that the Companies' newest large-frame combustion turbines (Brown 6 and 7) operated between 665 and 814 hours.

Q. Do you have any comments about Mr. Baron's proposal to include a buy-through provision in the tariff?

A. Yes. From a theoretical perspective there is nothing wrong with buy-through provisions. But as a practical matter, including a buy-through provision in the tariff is problematic. A buy-through provision allows an interruptible customer to buy power at the prevailing market price rather than actually interrupting its load. The problem with buy-through provisions is that they encourage customers that cannot truly interrupt their load to sign up for curtailable service, and they also encourage customers that have no intention of ever interrupting their load to sign up for service under the rider. Many customers will automatically buy-through instead of interrupting their load, regardless of the market price. They generally evaluate the feasibility of interruptible service by comparing the expected cost of buying through to the monthly CSR credit they will see on their bill. Over the years, I have seen manufacturing companies sign up for interruptible service with buy-through provisions when I knew within reason that they would never voluntarily shut down their production lines and send employees home if they were called upon to interrupt their load. It is impossible to verify whether or not the customer actually intends to interrupt its load. The problem with allowing customers that have no intention of interrupting their load to sign up under the tariff is that there may come a day when buy-through power is not available at any price and the utility must ask the customer to actually interrupt its load; or the utility may ask the customer to interrupt its load not because of the unavailability of power in the market but because of emergency conditions on the system. In such circumstances the utility will simply not have sufficient capacity to meet the load of its interruptible customers because it had not included curtailable load in the capacity planning process and thus had not installed generation capacity to serve the curtailable load.

In addition, buy-through provisions impose additional risk on the utility unless they are structured as take-or-pay arrangements. In a take-or-pay arrangement, the customer will commit that it will either take or reimburse the utility for the buy-though energy estimated to be needed before the hour. Without such an arrangement, the utility could buy additional energy on the market (potentially at high prices) and the customer could use far less than estimated, leaving the utility with reimbursement for less than was procured for the customer's benefit.

Furthermore, buy-through provisions require careful, time-consuming administration that cannot be accomplished for very many customers with the Company's existing staff. The specific hours when the Company interrupts are often some of the most challenging hours already (because interruptions will typically occur when generation has been lost or market prices are extraordinarily high). The Company needs its existing staff in those times to ensure that service to other customers is not negatively impacted.

Q. Do any of LG&E's contracts for interruptible service currently include buy-through provisions?

A. Yes.

Q. Does the Company propose to cancel the buy-through provisions with its current customers?

A. No. Although LG&E plans to honor the buy-through provisions with its current customers, the Company is concerned about being required to extend buy-through provisions to new interruptible customers. One possible compromise on this issue is to specify in the tariff that a customer must take service under the CSR tariff for three years without buy-through in order to be eligible for the buy-through provision. This will provide some assurance that the customer is not signing up for curtailable service without the ability or the intention of actually interrupting.

Q. Do you have any comments about Mr. Baron's proposal to provide avoided fuel savings to CSR customers during periods of interruption?

A. Yes. Mr. Baron recommends revising the tariff to include an additional credit reflecting the fuel savings during the actual hours of interruption. Mr. Baron is correct that interrupting CSR load will generally result in avoided fuel costs, which are in addition to the avoided fixed costs reflected in the CSR credit. In developing the CSR credit the Companies wanted to retain a portion of the total savings for other ratepayers. As already mentioned, in the past the interruptible credit for KU was determined on the basis of a 33/66 percent sharing of the avoided fixed costs. However, the interruptible credit never reflected fuel cost savings. Therefore, the Companies determined that a reasonable approach would be to provide the fixed cost savings to the CSR customers through the interruptible credit but retain the fuel savings, which would be flowed directly through the fuel adjustment clause, for the Companies' other customers. We felt that this would be a reasonable balance considering that we were increasing the number of hours of interruption.

VII. Redundant Capacity Rider

Q. Do you agree with Mr. Baron's recommendations with respect to the proposed Redundant Capacity Tariff?

A. No. Mr. Baron's recommendations seem to be based on a misunderstanding of the purpose of the Redundant Capacity Rider. On page 54 of his testimony, Mr. Baron states the following:

> The redundant capacity rider is designed to recover incremental costs associated with the distribution system that may be incurred as a result of providing an alternative distribution feeder to a customer location.
>
> (Testimony of Stephen J. Baron, page 54.)

The Redundant Capacity Rider is not designed to recover the incremental costs incurred to provide an alternative distribution feed, but rather, the embedded distribution costs associated with distribution capacity that must be set aside by the company when a customer installs a back-up feed with firm capacity. Customers will request back-up distribution feeds because of reliability considerations. For many customers even a brief interruption of electric service is a very expensive proposition because once their process is interrupted it is very costly to get it up and running again. For example credit card processing companies can lose large amounts of money if their computer systems are off-line. Package sorting companies cannot afford an outage during peak sort times. And many chemical companies cannot afford to have the manufacturing process stopped in the middle of the process. For this reason many customers over the years have installed redundant back-up feeds so that their service can be switched over in the event that the primary feed goes down due to events such as storm or equipment failure. The customer's expectations are that the capacity associated with the back-up feed is firm and will be there in the event that it is needed.

We do not agree with Mr. Baron's recommendation that "for each instance wherein the Company proposes to charge a redundant capacity fee, the Company must provide to the customer an analysis that shows that the Company will in fact require additional distribution facilities (above the customer-provided contributions) in order to provide the redundant distribution capacity to the customer." Mr. Baron's proposal would create a subsidy for customers requiring firm distribution backup service. Customers with redundant feeds who desire firm back-up service impose a cost on the distribution system related to the distribution capacity that must be reserved to provide the firm back-up service. Mr. Baron's recommendation would in most cases provide the customers requiring firm backup service a free ride, which is contrary to the Commission's policy articulated in Case No. 90-158 where it stated that, "If any customer has access to electricity whenever it is demanded, that customer should bear the responsibility of some portion of demand-related costs."[33] Mr. Baron's recommendation would, in most circumstances, allow customers that require firm backup feeds to avoid paying a portion of demand-related distribution costs necessary to provide service.

Q. How would the Companies try to ensure that the capacity is available on a back-up feed in the event that it is needed by a customer?

A. A portion of the distribution capacity on the circuit(s) feeding the redundant back-up feed must be set aside to ensure that it is available when, and if, the customer's load needs to be switched

33 Order in Case No. 90-158, dated December 21, 1990, page 58.

to the back-up feed. In some cases this would mean reserving capacity on a circuit all the way back to the substation. LG&E and KU would not be able use this capacity to serve load growth on its system because it would have to keep that capacity available to supply service to back-up feeds on the circuit. The end result is that customers with firm back-up feeds would tie up capacity on two circuits. Without the Redundant Capacity rider, they would only pay for the capacity on their primary circuit through the rate. While customers are required to pay the incremental cost of the facilities that must be installed to construct the back-up feed, without a reservation charge, they would not be required to pay anything for the distribution capacity needed to deliver power to the back-up feed.

Q. Would the proposed Redundant Capacity Tariff allow the Companies to provide firm-backup distribution capacity without this service being subsidized by other customers?

A. Yes. Since any customer that requests a redundant back-up feed would be required to pay the incremental cost of installing the feed plus a distribution demand component designed to recover the cost of the capacity on the circuit(s) that must be set aside in order to provide service to the redundant back-up feed, all costs associated with providing this service would be borne by the customers taking the service.

VIII. Non-Conforming Load

Q. Why is it necessary for the Companies to offer a Non-Conforming Load Service ("NCLS")?

A. NCLS partially fills a void contained in the Companies' tariffs. Most of the Companies' large industrial customers take service under LG&E's Rate LP-TOD and KU's Schedule LCI-TOD.

Service under these schedules is limited to a maximum load not exceeding 50,000 KW. Schedule LCI-TOD states that, "customers with new or increased load requirement that exceed 50,000 KW will have a rate developed as part of their contract based upon their electrical characteristics." NCLS would be available to customers with non-conforming loads greater than 20,000 KW.

Q. Why is it important to limit the size of customers served under Schedule LCI-TOD and Rate LP-TOD to 50,000 KW?

A. In approving Schedule LCI-TOD and Rate LP-TOD, the Commission recognized that serving a customer that is larger than 50,000 KW can have serious consequences to the planning and operation of the utility system. By retaining the right to develop a special contract for such customers, the Companies can (a) determine if they have sufficient capacity available to serve such a customer without detrimentally impacting other customers, (b) develop rates, to be approved by the Commission, for such service that accurately reflect a recovery of those costs imposed by those customers and ensure that other customers are held harmless from any additional costs caused by these larger customers, (c) impose tailored terms and conditions to address specific operational or other issues caused by these customers, and (d) require sufficient minimum contract periods and payments to ensure that all significant investments are recovered from the customers causing them.

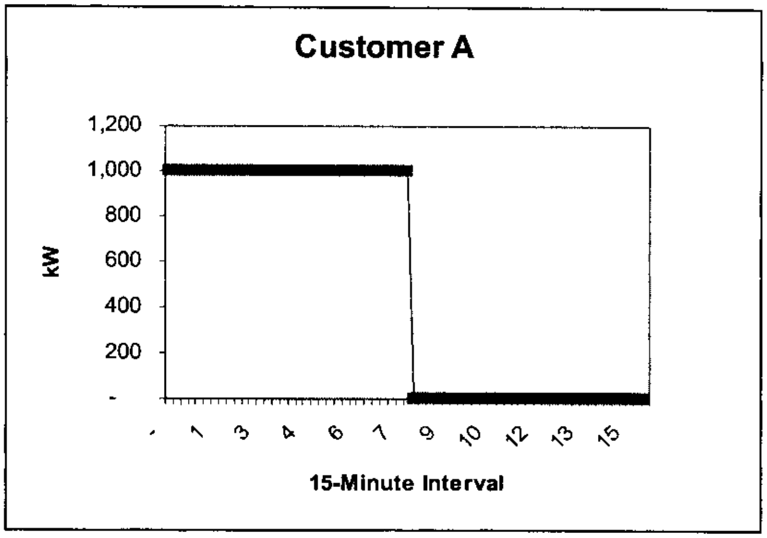
Q. Why is a shorter demand measurement window appropriate when the customer's load is expected to change rapidly on a regular basis?

A. Load swings over short periods of time can create operational problems for the utility and can cause the utility to incur generation capacity cost not measured in meeting the needs of the customer. Under Schedule LCI-TOD and Rate LP-TOD, customer demands are measured over a 15-minute integrated basis. What this means is that changes in a customer's demand are averaged over 15-minute time intervals to determine its maximum monthly demand. Although this 15-minute measurement window will reasonably reflect the demand imposed on the system by most customers, a customer load could rapidly swing in such a way that the customer's demand at any given instant could significantly exceed the demand measured over a 15-minute interval. The utility must stand ready to meet the customer's higher instantaneous demand, so the demand measurement used for billing purposes should be more reflective of this instantaneous demand. Although a customer's demand on a 15-minute basis might be 50,000 kW, for example, its maximum instantaneous demand could be 80,000 kW. The utility must have sufficient generation and/or inter-tie capability to provide the additional 30,000 kW. A rate determined using a 15-minute demand would not adequately reflect the capacity cost of providing the additional 30,000 KW.

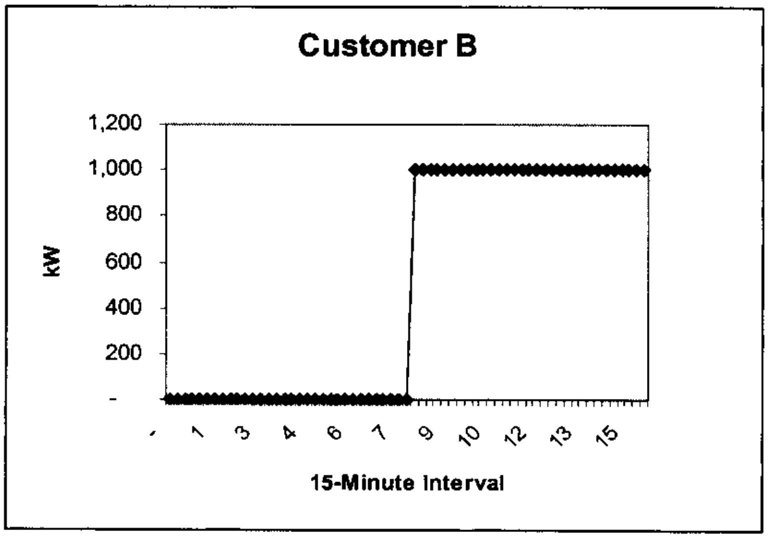
Q. But doesn't this situation exist with all demand customers?

A. Yes, although not to the extent contemplated in Schedule NCLS. Load swings by smaller customers do not present the same problems as the larger customer. With smaller customers, the load swings of one customer will tend to cancel out the load swings of other customers. This phenomenon, which is generally referred to as "load diversity", can be depicted graphically by examining the hypothetical loads of two customers with peak demands that occur at different times during a 15 minute interval. In this example, Customer A has a 1,000 kW demand occurring during the first half of a 15-minute interval and Customer B has a 1,000 kW demand occurring during the second half of the 15-minute interval. A graph of Customer

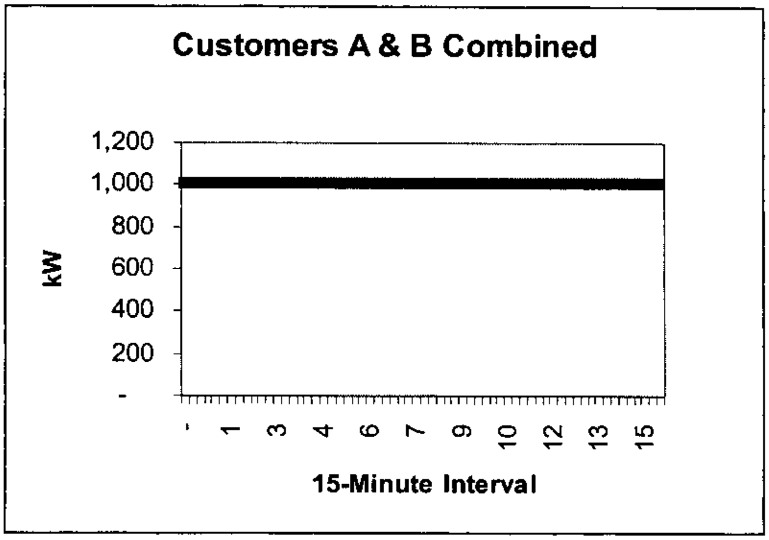
A's load takes on the appearance of a step function that drops from 1,000 KW to zero in the second half of the 15-minute interval, as follows:



A graph of Customer B's load also takes on the appearance of a step function that jumps from zero to 1,000 KW in the second half of the 15-minute interval, as follows:



As can be seen from these two graphs, Customer A's load is up when Customer B's load is down, and Customer B's load is up when Customer A's load is down. When the loads for these two customers are aggregated (or *convolved*), the combined load for the two customers flatten out as follows:

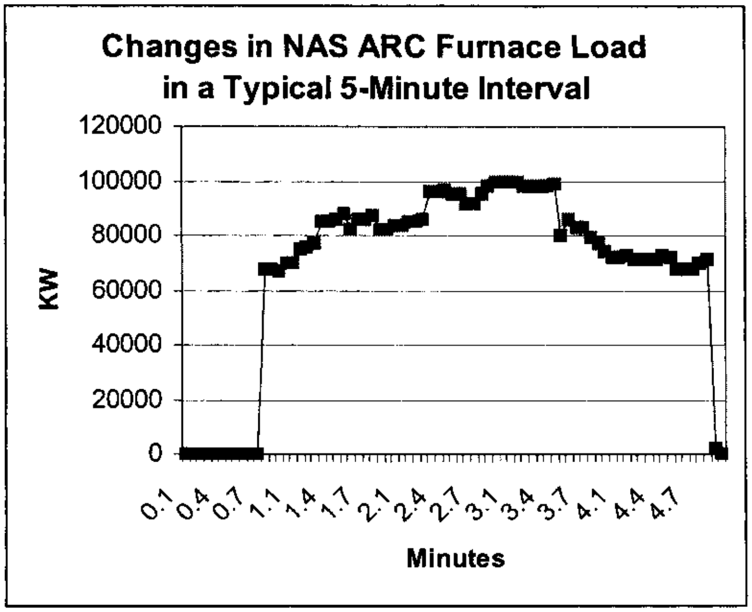


Although this is an idealized example, it illustrates how customer load diversity helps alleviate demand spikes on the system.

Q. Can customer load diversity alleviate the operational and planning problems associated with the large momentary load swings of a customer such as North American Stainless ("NAS")?

A. No. NCLS would be applicable to customers whose "load either increases or decreases twenty (20) MVA or more per minute or seventy (70) MVA or more in ten (10) minutes when such increases or decreases exceed one (1) occurrence per hour during any hour of the billing period." NAS's load will swing by more than 80,000 KW in the matter of seconds and by more than 100,000 KW in a matter of minutes. The following graph shows the change in

NAS's load during a typical 5-minute interval[34] when it starts its arc furnace:



During this typical 5-minute interval, NAS's load went from 0 KW to 100,000 KW and back down to 0 KW. To help put this in perspective, consider the fact that during two minutes NAS's load changed by an amount significantly greater than the size of the entire load of KU's next largest customer – a large automobile manufacturer located near Lexington – and by an amount almost three times the size of the largest customer on LG&E's system. NAS's load will change in a two-minute period by an amount greater than the entire summer demand of approximately 20,000 residential customers on KU's system. There are no other large industrial loads on LG&E and KU's combined system to offset load spikes the size of those

34 The 5-minute interval depicted in the graph represents the 5-minute period between 12:19 and 12:24 PM on

created by NAS. Load swings the size of those of NAS can have serious implications on utility operations and planning. KU must at all times be able to respond to these swings. There must be sufficient generation capacity or reserved capacity from other utilities to meet the maximum demand placed on the system by NAS. KU must also take special care to maintain control of the system as NAS reduces its load.

Q. **But shouldn't KU have anticipated this prior to serving NAS in the first place?**

A. Yes, and it appears that they did. Although I wasn't personally involved in negotiating the NAS contracts, I have prepared offers for several customers with loads similar to NAS. When the load of a prospective large industrial customer is expected to fluctuate like NAS's, it is important to either include a minimum demand that compensates for the low 15-minute demands that are anticipated for the customer or to determine the billing demand on a 5-minute interval. It is my understanding that when the arc furnace was added, NAS asked to take service under LCI-TOD but KU was unwilling to serve a non-conforming load of this size under LCI-TOD. Consequently, a special contract was developed for NAS that included a minimum contract demand. That special contract was developed using load and other information provided by NAS.

Q. **Do other Commissions permit utilities to determine demands on a 5-minute basis for customers with non-conforming load?**

A. Yes. I am aware of the following utilities that have large power tariffs that permit the use of a 5-minute demand for non-conforming loads: Sierra Pacific Power Company, Nevada Power Company, Delmarva Power & Light, Pacific Gas & Electric Company, Southern California

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January 6, 2004.

Edison Company, and San Diego Gas & Electric Company.

Q. NAS witness Charles Buechel suggests that the rate for service under NCLS is too high because of the high rate of return for NAS in KU's cost of service study. Do you agree with his assessment?

A. No. Mr. Buechel claims that the rate of return for NAS is 22.2%. His use of this rate of return is misleading and disingenuous. The 22.2% rate of return referenced by Mr. Buechel reflects service under NAS's terminated special contract. It is anticipated that NAS will see a rate *decrease* of $1,900,000 moving from its old special contract to Schedule NCLS. It is important to keep in mind that NAS is the *only* customer in this proceeding with a proposed rate decrease. The 22.2% unadjusted rate of return referenced by Mr. Buechel has no relevance whatsoever, unless NAS wants to remain under the old special contract.

In addition, it is important not to give too much weight to the actual rate of return for NAS from the cost of service study. There is a strong chance that it is overstated. No attempt was made to modify the cost of service study to account for either 5-minute or 15-minute demands. In preparing the cost of service study, all demand allocators were determined the same way they were developed in past cost of service studies – using hourly demands. Therefore, KU's cost of service study does not – and cannot – account for customer load swings during an hour. None of KU's other large customers exhibits momentary load swings of the magnitude of NAS. Consequently, on a 5-minute basis NAS's coincident peak and non-coincident peak demands would have been higher relative to other customer classes. Thus, had the demand allocators been determined in the cost of service study on a 5-minute basis, the rate of return for NAS would have undoubtedly been significantly lower, perhaps supporting a rate increase rather than the decrease the customer will likely see under Schedule NCLS. Mr. Buechel, on the other hand, is proposing that NAS be served under Schedule LCI-TOD, which is KU's standard rate for industrial customers with demands less than 50,000 KW. Schedule LCI-TOD was not designed to reflect load characteristics such as those of NAS. Mr. Buechel's proposal would inappropriately result in an even larger rate decrease to NAS.

Q. Did the canceled special contact with NAS permit KU to interrupt service for 10 minutes during system contingencies?

A. Yes. Because NAS's load was so large and subject to violent fluctuations, this was a key component of the cancelled special contract and is critical to the Company's ability to continue to provide service to NAS.

Q. What is the purpose of the curtailment rights reserved by the Companies under the heading "SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA" of the NCLS tariff?

A. In spite of the total limits on non-conforming loads that are placed in the NCLS tariff, the non-conforming loads that could exist under the NCLS tariff would dramatically increase the risk that the Companies would face operational problems in certain events. One example of those types of events would be a sudden, unplanned loss of generation. The purpose of these "system contingency" curtailment rights reserved by the Companies is to address the fact that, during certain limited times and for very brief periods (such as, but not limited to, the period immediately following a sudden, unplanned loss of generation), the Companies' electrical system cannot sustain service to rapidly changing non-conforming loads without endangering the quality of service to all other customers and/or the reliability of the transmission grid. The majority of the Companies' rapid load following capability, which would typically be made available to and utilized by the non-conforming load customers, would be needed by the Companies for their entire combined system in the event of such a system contingency. Thus, the Companies have reserved this limited right. Moreover, as demonstrated by NAS's execution of the Special Contract between KU and North American Stainless that terminated on March 31, 2004, this type of right has in the past been acceptable operationally for an electric arc furnace (which is the most likely type of non-conforming load). More importantly, that Special Contract was approved by the Commission as a reasonable manner for KU to balance the interests of NAS against the interests of KU's other customers and to protect KU's overall system while complying with industry standards.

Q. Why are the curtailment rights reserved by the Companies under the heading "SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA" needed if an NCLS tariff customer elects service under the Curtailable Service Rider Tariff?

A. These separate curtailment rights serve entirely separate purposes. The "system contingencies" curtailment rights are meant to address specific operational concerns arising out of the existence of a non-conforming load on the Companies' combined system. On the other hand, the curtailment rights available when a customer elects to take service under the Curtailable Service Rider are meant to give the customer certain credits for allowing the Companies' to delay the acquisition of additional capacity. Thus, the Curtailable Service Rider is structured in a way that reflects the value to the Companies of the curtailment right, but it is not structured to address the operational concerns that are specific to non-conforming load customers. Among other reasons, these additional "system contingency" curtailment rights are necessary because interruptions under the Curtailable Service Rider require at least 10 to 30 minutes notice of an interruption. This is insufficient lead time for the Companies to address the system contingency and industry system performance criteria issues that might arise. Furthermore, these "system contingency" curtailment rights are tailored to address specific operational concerns and thus are of a very limited duration.

Q. Mr. Buechel at page 15 of his prefiled testimony states that there is no relationship between the non-conforming load definition of 20 MVA swings in one minute and the 70 MVA swings in ten minutes and the system capability. He goes on to accuse the Company of developing the definition of non-conforming load around one customer. Would you comment?

A. Yes. Although NAS's load is certainly non-conforming, the definition of "non-conforming load" was not developed around NAS. Basically, the non-conforming load definition is designed to capture those large loads which are dramatic, frequent, and regular in occurrence. Normal loads have gradual changes, or perhaps dramatic, but infrequent and irregular swings.

KU and LG&E have 16 coal-fired generators which are capable of following load swings. In response to rapid changes in load, the Companies' experience is that they can be depended on to ramp up and down at a rate of roughly 3 MW per minute. Roughly half of these units (more precisely 6 to 10) will be capable at any time of ramping up or down. That provides a typical system load following capability of approximately 24 MW per minute. The 20 MVA per minute swing was derived by using that typical system load following capability and rounding down for the sake of reliability, as any inability to follow a rapid swing in load at a particular time could negatively impact service to all other customers.

The 70 MVA swing in ten minutes was derived in similar fashion. Under ECAR and NERC performance criteria the utilities are expected to meet certain standards which must be reported regularly. After accounting for commitments to ensure that those standards are met, the changes in system load must be maintained to within a 74 MW tolerance in ten–minute intervals. Again, after rounding down to maintain an adequate margin of error to protect service to all customers, a 70 MW fluctuation in ten minutes was chosen as the threshold for the definition.

Q. Does this method of defining a non-conforming load make sense and is it fair?

A. Yes to both questions. Contrary to Mr. Buechel's claim, the definition of a non-conforming load is based on the Companies' system capability and the requirements of ECAR and NERC, which the utilities are obliged to follow to ensure the reliability of service to all customers. In fact the definition tracks exactly the load following capacity of the system.

For a customer like NAS, the Companies must be ready to provide up to 100 MW of power within two minutes or less. That power may then be used for only a few minutes at a time. At the same time, the Companies have obligations to other customers, to the integrity of the system, and to neighboring utilities. That requires that it have the capacity to provide power to the non-conforming load customer for brief periods of time while at the same time being ready to respond to demands from other customers and system contingencies.

There are obvious and unavoidable costs involved in serving the unique load characteristics of customers such as NAS. The NCLS demand charge is necessarily higher than for LCI-TOD customers who typically have less demand and fewer and less dramatic fluctuations in demand. That is why a special rate for non-conforming loads was developed -- to capture the costs unique to those non-conforming loads.

Q. Do you believe that the proposed NCLS rate is reasonable?

A. Yes, I do.

IX. Gas Cost of Service Study

Q. Did any of the intervenor witnesses comment on LG&E's gas cost of service study?

A. Yes. KIUC witness Richard A. Baudino and Attorney General witness Brown-Kinloch offer limited comments on the gas cost of service study. Mr. Baudino criticizes LG&E's cost of service study because it uses the zero-intercept methodology instead of the minimum system methodology for classifying the cost of distribution mains. He claims that the zero-intercept method is "conservative" and suggests that a larger portion of mains should be classified as customer-related. Mr. Brown-Kinloch, on the other hand, criticizes the study because it separates mains between (i) high-pressure pipe and (ii) medium/low-pressure pipe. He criticizes the study because this step was not taken in the cost of service study submitted in the Company's last base gas rate case.

Q. Are these criticisms valid?

A. No. Both witnesses made selective modifications to LG&E's cost of service study that produced results favoring their special interests. Specifically, Mr. Brown-Kinloch's proposed modifications to the cost of service study would shift costs away from residential customers and onto large gas transportation customers, and Mr. Baudino proposed modifications that would shift costs away from large transportation customers and onto residential customers. The following table shows the impact on the class rates of return of Mr. Brown-Kinloch's and Mr. Baudino's recommendations:

	AG Witness Kinloch's Version of the Cost of Service Study	Company's Cost of Service Study As Originally Submitted	KIUC Witness Baudino's Version of the Cost of Service Study[35]
Residential Rate RGS	2.29%	1.75%	1.09%
Commercial Rate CGS	8.00%	6.85%	9.99%
Industrial Rate IGS	7.13%	6.42%	11.40%
As-Available Service Rate AAGS	1.54%	10.54%	18.72%
Firm Transportation Service Rate FT	8.12%	30.53%	48.77%
Special Contracts Customers	(2.29%)	21.27%	35.78%
Total Company	3.56%	3.56%	3.56%

As can be seen from this table, the class rates of return for Rate RGS (serving residential customers) and Rate FT (serving large industrial and commercial customers) in the Company's cost of service study fall between the rates of return for these classes using the methodologies recommended by Mr. Brown-Kinloch and Mr. Baudino.

Q. Do you have any problems with the cost of service methodology recommended by Mr. Baudino?

A. Yes. Mr. Baudino recommends the use of the minimum system methodology for classifying the cost of mains. In my opinion, this approach is inappropriate for a number of reasons: First,

35 Mr. Baudino describes the impact of the changes without actually computing class rates of return.

it assumes that the cost associated with a minimum size pipe is customer-related. The problem with this assumption is that a minimum size pipe would still have the capability of delivering gas to customers and thus meeting customer demands. Therefore, a portion of the minimum size pipe is still related to demand. The advantage of the zero-intercept is that it determines the cost of a zero-sized pipe using a weighted regression analysis, thus theoretically determining the cost of a pipe without any capability of meeting gas load. The zero-intercept therefore allows fixed customer-related costs to be separated from costs that vary with demand. Second, the zero-intercept is less subjective than the minimum system methodology. Third, the zero-intercept methodology has been accepted by the Commission on a number of occasions, including LG&E's last gas base rate case.

Q. Mr. Brown-Kinloch rejects splitting distribution costs between high and medium/low pressure systems. Does he raise legitimate concerns?

A. No. Mr. Brown-Kinloch correctly points out that we added an additional step in the cost of service study, a step we have been considering for several years and which is more consistent with the approach used in the electric study and also reflects operational reality on the distribution system. A refinement was made to the cost of service study to separate the high-pressure delivery system from the medium/low-pressure delivery system. The high-pressure delivery system and the medium/low-pressure system are operated as two distinct systems. The high-pressure system feeds the medium/low-pressure system. As a result the high-pressure system is used to serve all customers on the system. However, some customers are not served from the medium/low-pressure system and are too large to take service from the medium/low-pressure system. Since these customers do not utilize the medium/low-pressure system they should not be allocated any of the costs associated with the medium/low-pressure system. Specifically, LG&E's special contract customers and many of its FT customers take service solely from the high-pressure system. The medium/low-pressure system is not used in delivering gas to these customers. Therefore they should not be allocated costs of the medium/low pressure system which is not used to provide service to these customers.

The high-pressure and medium/low-pressure gas systems are exactly analogous to the primary and secondary voltage systems on the electric distribution system. In its electric cost of service study, LG&E's distribution system is separated into primary and secondary voltage systems. Just as the high-pressure and medium/low-pressure systems for LG&E's gas delivery operations, the primary system feeds the secondary system. Customers taking service at primary voltages do not receive an allocation of the secondary distribution system. In separating gas distribution costs between the high-pressure and medium/low-pressure system, we are simply following the same methodology utilized in the Company's electric cost of service study.

LG&E differs from most other gas distribution companies in that very little of its costs are functionalized as transmission facilities. Most other gas distribution utilities of which I am aware have significant amounts of transmission costs recorded on their books. Transmission facilities are generally pressurized at high pressure. The reason that LG&E has less transmission investment than other gas distribution companies is the LG&E relies on Texas Gas Transmission LLC as a header system to directly feed its high-pressure delivery system. LG&E's transmission system is primarily used to support its underground storage facilities. Most other utilities of which I am familiar install a transmission system to bring the gas from their pipeline transporters to the local delivery system. Those utilities generally serve large industrial customers directly from their high-pressure transmission facilities. A larger portion of the distribution facilities of those utilities is pressurized at medium/low pressure. In the cost of service studies for those utilities, the customers taking service from the transmission facilities are not allocated any portion of the distribution system. Unlike many utilities, a large amount of LG&E's high-pressure pipe is recorded as distribution mains, rather than recorded as transmission mains. LG&E is therefore allocating its high-pressure system in a manner similar to the way that other utilities allocate their transmission systems.

Q. Did Mr. Brown-Kinloch object to functionalizing the overhead and underground conductor into primary and secondary systems in the electric cost of service study?

A. No, he did not object to the same type of split in the electric cost of service study.

Q. Is there a fundamental problem with adding your additional step in the gas cost of service study?

A. Not at all. This is refinement to the study, not a fundamental change in the methodologies used in the study. We are still using the same basic steps in the cost of service study and we are still using the zero-intercept methodology. We have simply made a refinement that more accurately reflects costs on the system consistent with the approach taken in the Company's electric cost of service study, and consistent with the way that other utilities allocate gas transmission costs.

Q. Did this refinement to the cost of service study affect any of the class rates of return?

A. Yes. It had the largest impact on the FT and Special Contract customers. Because most of these customers do not utilize the medium/low-pressure system, they were not allocated any of the costs associated with the medium/low-pressure system. As a result, the rates of return for these customers are higher than they would be if this refinement were not made.

Q. Did the refinement affect the way the rate increase was allocated to the customer classes?

A. No. The Company would have recommended the same approach for allocating the increase to the rate classes. The only group of customers whose rates of return would have possibly suggested anything different was the Special Contract customers. LG&E would not have increased the rates to the Special Contract customers even had the cost of service study indicated low rates of return for these customers because the special contract customers are all potential by-pass customers.

X. Allocation of Gas Rate Increase

Q. Do Mr. Baudino and Mr. Kinloch recommend a different approach for allocating the rate increase to the classes of customers?

A. Yes. Mr. Baudino allocates the rate increase in such a way that the large commercial and industrial customers served under Rate FT (under which his clients take service) will see a slight decrease. Mr. Brown-Kinloch allocates a large increase to the special contract customers. Otherwise, the approaches used by both witnesses are similar to LG&E's.

Q. Are there any problems with the way Mr. Baudino proposes to allocate the rate increase to the customer classes?

A. Yes. Mr. Baudino developed a methodology that would eliminate 25% of the inter-class subsidies. As a result, Mr. Baudino recommends a reduction in Rate FT. The Company is not proposing to reduce any rates, either for LG&E or KU. However, the major problem with Mr.

Baudino's proposal is that he is recommending an increase to the rates applicable to small business customers – Rates CGS, IGS, and AAGS – that would cause the rates of return for these classes to exceed 9.61%, 9.29%, and 12.38%, respectively. Mr. Baudino's proposal simply produces a decrease in Rate FT – the rate under which his clients take service – at the expense of driving the rates of return for Rates CGS, IGS and AAGS to unacceptable levels.

Q. Are there any problems with Mr. Brown-Kinloch's proposal for allocating the increase?

A. Yes. While recommending that the rate increase for Rate RGS be capped at 1 percentage point above the overall increase to recognize the principle of gradualism, he recommends a massive 32.95% increase to the special contract customers. All three of the special contract customers can potentially bypass LG&E's system, with all of them having threatened to bypass LG&E at least once. All three are located near potential pipeline transporters. The facilities of Texas Gas Transmission, LLC are located on the property of one of these customers. Given the proximity of these customers to the alternative pipeline transporters, it would be bad business practice to propose *any* increase to these customers, much less 32.95%. Mr. Brown-Kinloch claims that even with a 32.95% increase that these customers are making no contribution to fixed costs. This assertion is incorrect. Practically all of the transportation revenues from these customers represent a contribution to fixed costs. The loss of the contributions to fixed costs these customers are making would be a heavy price to pay for Mr. Brown-Kinloch's ill-advised proposal.

XI. Gas Rate Design

Q. Does Mr. Brown-Kinloch propose a different rate design than the Company?

A. Yes. He proposes a lower customer charge for Rate RGS. LG&E proposes to increase the monthly customer charge from $7.00 to $10.80; whereas Mr. Brown-Kinloch proposes to increase the charge to $8.00. As with his proposal regarding the electric customer charge, he completely ignores the customer-related costs from the zero-intercept methodology in identifying the costs he chooses to recover through the customer charge. In LG&E's last gas base rate case (Case No. 2000-080), Mr. Brown-Kinloch proposed to recover costs through the commodity component (distribution delivery charge) of the rate that were classified as customer-related in his own cost of service study. The Commission rejected Mr. Brown-Kinloch's proposal to recover customer-related costs through the distribution delivery charge. Even using his flawed approach for calculating the customer charge, however, Mr. Brown-Kinloch's methodology would support a $9.00 per month charge in this proceeding.[36] Yet, in computing his proposed customer charge, he arbitrarily selected $8.00.

Q. Do any of the other witnesses address any rate design issues?

A. Yes. KIUC witness Baudino submitted testimony concerning certain changes to the terms and conditions of the Company's transportation schedules. These issues are addressed by LG&E witness Clay Murphy.

XII. Miscellaneous Service Revenues

Q. Does Mr. Brown-Kinloch object to any of the proposed increases in miscellaneous charges?

A. Yes. He feels that the disconnect/reconnect charge should not be increased. The charge is currently $18.50 for LG&E, and the Company is proposing to increase the charge to $23.00. For KU, the charge is currently $10.50 during working hours and $38.00 after working hours. KU is proposing a flat charge of $31.00. Mr. Brown-Kinloch also recommends that the Commission apply the principle of gradualism and only allow the Company to increase the meter testing fee and the third-trip inspection fee by half the amount proposed by the Company.

Q. Do you have any comments about Mr. Brown-Knloch's recommendations?

A. Yes. In assessing the Companies' proposal, the Commission should recognize that the increase was already mitigated to a significant degree by the way that the costs used to support the charges were calculated. In developing the cost support for these charges, the Companies used raw, unburdened costs (i.e., the costs that did not include overheads). The costs used to develop the proposed charges were conservative; therefore, in developing the proposed miscellaneous charges, the Companies already recognized the principle of gradualism.

The Commission should also realize that the proposed increases in the miscellaneous service charges serve to reduce the amount of revenue collected through base rates. If these costs are not recovered through the miscellaneous charges from the customers receiving the services, then they must be collected through base rates. One of the reasons that LG&E and KU are proposing to increase these charges is to encourage customers not to utilize these

36 Exhibit DHBK-4 of Mr. Brown-Kinloch's testimony indicates that a monthly customer charge of $9.00 could be

services as often. It costs real dollars every time a customer is disconnected and reconnected, every time a meter is tested that does not need to be tested, and every time an extra trip is made to inspect a gas line for a contractor. When customers realize that they will be assessed a compensatory charge for these services, then the frequency of their occurrence may possibly decrease, resulting in cost savings to the utility and cost savings to the customers requesting the services. If the charge is not compensatory, then customers may choose to use these services more frequently than they should, which results in costs being borne by utility's other customers.

XIII. Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

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supported using his flawed approach to identifying costs to be recovered through the customer charge.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and says he is the Principal and Senior Consultant for The Prime Group, LLC, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

____
William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of April 2004.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

TAMMY J. ELZY
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
My Commission Expires Nov. 9, 2006