COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF THE UNION LIGHT, HEAT AND POWER COMPANY TO ADJUST ELECTRIC RATES	)))	CASE NO. 91-370

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O R D E R

On November 4, 1991, The Union Light, Heat and Power Company ("ULH&P") filed an application with the Commission requesting authority to increase its electric rates for service rendered on and after December 4, 1991. The proposed rates would increase annual electric revenues by $29,702,741, an increase of 20.4 percent, based on normalized test-year sales. This Order grants an increase in annual electric revenues of $22,334,942, an increase of 15.1 percent, based on normalized test-year sales.

The Commission granted motions to intervene filed by the Attorney General, by and through his Utility and Rate Intervention Division ("AG"); the Newport Steel Corporation ("Newport Steel"); and joint movants Virginia Anderson, Hazel Buchanan, and Citizens Organized to End Poverty in the Commonwealth ("CO-EPIC").

The Commission suspended the proposed rate increase through May 3, 1992 in order to conduct an investigation into the reasonableness of the proposed rates. A public comment hearing was held at Thomas More College in Crestview Hills, Kentucky, on March 5, 1992, to allow interested parties an opportunity to express their concerns about ULH&P's proposed rate increase. A

public hearing was held in the Commission's offices in Frankfort, Kentucky, on March 17-20 and 23, 1992 with all parties of record represented. Simultaneous briefs were filed on April 20, 1992. All information requested during the hearing has been submitted.

On February 10, 1992, ULH&P filed a petition requesting authority to record on its books as a deferred debit the increase in purchased power expense to be incurred as a result of a decision by the Federal Energy Regulatory Commission ("FERC") to allow increased rates for purchased power to become effective subject to refund on February 13, 1992. The increased rates for purchased power were requested by Cincinnati Gas and Electric Company ("CG&E"), the parent and wholesale power supplier of ULH&P. This issue was heard at the commencement of the public hearing on March 17, 1992. On April 17, 1992, the Commission denied ULH&P's request.

COMMENTARY

ULH&P operates as a public utility providing electric and gas service in Boone, Campbell, Grant, Kenton, and Pendleton counties. Within those counties, ULH&P distributes and sells electricity to approximately 106,270 customers.

TEST PERIOD

ULH&P proposed and the Commission has accepted the 12-month period ending July 31, 1991 as the test period for determining the reasonableness of the proposed rates. In utilizing the historic test period, the Commission has given full consideration to appropriate known and measurable changes.

NET ORIGINAL COST RATE BASE

ULH&P proposed a jurisdictional net original cost rate base of $95,645,272.[1] The Commission has made the following modifications to the proposed rate base:

Accumulated Depreciation

In computing its proposed electric jurisdictional net original cost rate base, ULH&P used the test-year end balance for accumulated depreciation. The AG proposed that the test-year end balance should be adjusted to reflect his proposed depreciation adjustment. The AG noted that the Commission routinely adjusts accumulated depreciation by the amount of the depreciation adjustment, and that ULH&P offered no evidence on why this adjustment was inappropriate.[2] ULH&P responded that it never believed this adjustment was appropriate because it improperly values the plant as of the end of the test year, improperly reflects an ongoing level of plant, and represents an arbitrary adjustment which is both inappropriate and inconsistent with the treatment of similar adjustments made to operating results.[3] However, ULH&P presented no evidence to support these allegations.

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1 Schedule B-1 of the Application.

2 DeWard Direct Testimony, page 8.

3 Lonneman Rebuttal Testimony, page 2.

We note that the AG has correctly stated the past practice employed by the Commission. The arguments presented by ULH&P have not persuaded us to reject the AG's adjustment. No authoritative basis has been offered by ULH&P to support a departure from the Commission's long standing practice. Therefore, the Commission will include adjustments to test-year depreciation expense, explained elsewhere in this Order, in the accumulated depreciation used in the determination of rate base. The adjustments increase accumulated depreciation by $14,909.

Prepayments

ULH&P proposed to include $83,041 for the PSC Assessment[4] and $5,236 for auto license taxes as a part of the prepayments component of rate base. ULH&P argues that such expenses, which are applicable to more than a one month period, are considered to be a prepayment. These expenses represent funds which, in ULH&P's opinion, had to be expended prior to their recovery through rates and should be recognized in rate base to compensate ULH&P for this delayed recovery.[5] The AG proposed to remove these two items from the rate base determination, citing the fact that the Commission did so in Case No. 90-041.[6]

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4 Referred to by ULH&P as "KYPSC Maintenance Tax."

5 Response to the Commission's Order dated December 17, 1991, Item 5.

6 DeWard Direct Testimony, page 10.

The Commission is not persuaded by ULH&P's arguments. The classification of the PSC Assessment and auto license taxes as prepayments allows ULH&P to recognize the expense over the entire year, rather than in the month of payment. ULH&P has not performed any lead or lag analysis on these payments. Also, ULH&P has not satisfactorily explained why it should earn a return on taxes it has already paid. As the Commission determined in Case No. 90-041:

> [T]he PSC Assessment and the auto license taxes represent liabilities which are paid for a specific, present time obligation. The rationale employed by ULH&P could be just as easily applied to other of its obligations, such as property taxes and income taxes. . . . These taxes are included in the operating expenses of ULH&P and are recovered from ratepayers through rates. ULH&P would enjoy a double benefit if it were also allowed to earn a return on these taxes.[7]

The Commission has excluded the PSC Assessment and the auto license taxes from the prepayments included in the rate base.

Cash Working Capital Allowance

ULH&P proposed to include in rate base $6,252,870 as a cash working capital allowance. ULH&P determined the allowance using the 45 day or 1/8 formula methodology and then added 10 days of purchased power expense. ULH&P stated that the 10 days represent the number of days it has to finance the purchased power costs before recovery is received from customers. ULH&P arrived at the 10 day figure by combining the number of days after the end of the

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7 Case No. 90-041, An Adjustment of Gas and Electric Rates of The Union Light, Heat and Power Company, Order dated October 2, 1990, page 10.

month it pays its purchased power bill, with the midpoint number of days for a consumption period. This equals 35 days. This sum was then subtracted from the 45 days used in the traditional formula approach.[8] ULH&P also noted that FERC adjusts for purchased power when it uses the formula approach.[9]

The AG opposed the inclusion of the 10 days of purchased power expense in ULH&P's calculation of cash working capital. The AG argued that inclusion of this one item was inappropriate, and excludes other items which have substantial lead days.[10]

The Commission has traditionally used the 1/8 formula approach in electric utility rate cases and find no basis to now depart from that practice. Concerning the addition of purchased power expense to that calculation, the Commission notes that ULH&P has performed no lead-lag studies for this case.[11] Thus, the use of 10 days is at best an assumption of the time this expense must be financed, not a known period of time. The Commission also notes that FERC will allow an adjustment to the results of the 1/8 formula method when it has been demonstrated that fossil fuel

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8 Bruegge Direct Testimony, pages 5 and 6.

9 Transcript of Evidence ("T.E."), Vol. I, March 17, 1992, page 207.

10 DeWard Direct Testimony, page 7.

11 T.E., Vol. I, March 17, 1992, page 208.

expense is a substantial component of the operation and maintenance expenses and the actual lag in the payment of fossil fuel is known. If an adjustment of fuel expense lag is made by FERC, then a further adjustment will be made to the formula results to recognize the increased importance to the utility of purchased power expense.[12] We cannot adopt ULH&P's proposed modification to the traditional 1/8 formula methodology, even if we chose to follow the stated position of FERC. As ULH&P has noted in its brief, "[t]he Commission has been presented with no evidence which would support departure from past practice."[13] Therefore, we have adjusted the allowance for cash working capital to exclude the 10 days of purchased power expense and to reflect the accepted pro forma adjustments to operation and maintenance expenses, which results in a cash working capital allowance of $2,535,132.

Deferred Income Taxes

ULH&P deducted $13,726,430 in deferred income taxes in the calculation of its rate base. The AG proposed an offset reduction to rate base of $2,256,871, which represents his calculation of the accrued liability associated with uncollectible accounts, post-retirement benefits, and vacation pay. The AG claims that without this adjustment ratepayers will be required to pay for the

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12 Response to AG Hearing Data Request No. 7, Docket No. RM84-9-000, Calculation of Cash Working Capital Allowance for Electric Utilities, Termination Order dated October 15, 1990.

13 Brief of ULH&P, page 8.

recorded book expenses as well as a return on the deferred tax charges included in rate base. The AG further claims that his adjustment allows ratepayers some measure of relief from these expenses which are recorded on ULH&P's books but are not funded.[14]

ULH&P opposed the AG proposal, noting that these accounts reflect situations where the book expense occurs before the tax deduction. Because deferred tax accounting has been followed, the ratepayer has benefitted from lower tax expense.[15]

The Commission notes that the AG proposed a similar adjustment in Case No. 90-041, except that he only proposed to eliminate the questioned deferred tax balances, not a corresponding accrued liability. However, the evidence convinces the Commission that the findings adopted in Case No. 90-041 should be readopted here:

> [r]atepayers have benefited from deferred income tax debits since at the time the debits were recorded, book income tax expense was lower than the actual income tax liability. Ratepayers benefit from deferred income tax credits as the tax timing differences which produced the credits reverse.[16]

The Commission will include in the determination of ULH&P's jurisdictional net original cost rate base the test-year end balances of the deferred income taxes, as were included by ULH&P.

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[14] DeWard Direct Testimony, page 9.

[15] Brief of ULH&P, page 9.

[16] Case No. 90-041, Order dated October 2, 1990, page 12.

Based upon the previous findings, the Commission has determined the jurisdictional electric net original cost rate base for ULH&P at July 31, 1991 to be as follows:

Total Utility Plant	$151,975,821
Add:	
Materials and Supplies -	
Distribution	70,214
Other	10,933
Total Materials and Supplies	81,147
Prepayments	144,418
Cash Working Capital Allowance	2,535,132
Subtotal	2,760,697
Deduct:	
Reserve for Accumulated Depreciation	49,093,137
Accumulated Deferred Income Taxes	13,726,430
Investment Tax Credits	96,010
Subtotal	62,915,577
Total Jurisdictional Electric Net Original Cost Rate Base	$ 91,820,941

CAPITAL

ULH&P proposed a total capitalization of $161,152,742.[17] The proposed capitalization included the average daily balance of short-term borrowings for the test year and the total of all investment tax credits as of the test-year end.

The AG proposed a total capitalization of $162,116,790.[18] The difference between the AG's proposal and ULH&P's was that the AG

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17 Mosley Direct Testimony, Exhibit JRM, page 1 of 7.

18 Weaver Direct Testimony, Exhibit CGK Weaver, Statement 20.

did not include the unamortized premiums and discounts on long-term debt in his total.

At test-year end, ULH&P's total capitalization, before the inclusion of Job Development Investment Tax Credits ("JDIC"), was $161,674,762.[19] In ULH&P's past cases, the Commission has generally allocated capital between electric and gas operations to determine the appropriate capital valuation for each type of utility service. The Commission believes that the use of this method is appropriate for rate-making purposes and has determined ULH&P's jurisdictional capital devoted to electric operations to be 52.771 percent of total capitalization based on the ratio of electric operations rate base to total company rate base as determined in Appendix B. The resulting capital assigned to jurisdictional electric operations is $85,316,929.

The Commission has increased this $85,316,929 by $3,706,088,[20] which is the jurisdictional amount of JDIC applicable to electric operations. The JDIC has been allocated to each component of capital based on the ratio of each capital component to total capital excluding JDIC. Both ULH&P and the AG included all investment tax credits as JDIC, without removing the investment tax credits included in the determination of rate base

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19 Schedule A-3.9 of the Application and the Response to the Commission's Order dated November 14, 1991, Item 1, page 4 of 8.

20 Schedule B-6 of the Application, lines 3 and 4.

from the total or excluding the non-jurisdictional portion of the investment tax credits. ULH&P and the AG did not allocate the amounts to the components of capital. The Commission has traditionally followed the practice of allocating JDIC to the capital components. This treatment is entirely consistent with the requirements of the Internal Revenue Service that JDIC receive the same overall return allowed on the components of capitalization.

REVENUE AND EXPENSES

For the test period, ULH&P had actual electric jurisdictional net operating income of $8,982,177. ULH&P proposed several pro forma adjustments to revenues and expenses to reflect more current and anticipated operating conditions which resulted in an adjusted jurisdictional net operating income of a negative $6,857,458.[21] The proposed adjustments are generally proper and acceptable for rate-making purposes with the following modifications:

Weather Normalization

ULH&P proposed an adjustment to reduce revenues by $1,526,929 to reflect the test year's deviation from normal temperatures as measured in cooling degree days and heating degree days. ULH&P determined its normal temperatures and normal degree days based on the 30-year average data published by the National Oceanic and Atmospheric Administration ("NOAA") for the period from 1951 through 1980.

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21 Schedule C-2 of the Application.

The AG recommended that the Commission reject the proposed adjustment claiming, among other things, that (1) the methodology used by ULH&P to calculate the adjustment was questionable; (2) ULH&P's model does not separately identify temperature-sensitive load and non-temperature-sensitive load; (3) the proposal does not take into consideration the affects of weather on CG&E's allocation of costs to ULH&P; (4) the 30-year data for the period ended 1980 does not reflect the impact of the warming trend of the past decade; and (5) ULH&P's choice of a test year ended July 31, 1991 greatly impacts the magnitude of the adjustment.

ULH&P took issue with the AG's claims and defended its adjustment as one that produces reasonable results for rate-making purposes. ULH&P claimed that its methodology was appropriate and fully documented, and that separating loads into temperature-sensitive and non-temperature- sensitive components would introduce additional error into the weather normalization process. ULH&P stated that CG&E's cost allocation was based on a future test year that included normal temperatures and ULH&P opined that neither it nor this Commission should rely on any temperature normals other than the 30-year data published by NOAA. Finally, ULH&P argued that its choice of test year was not related to its proposed weather normalization adjustment but, if that were the case, it might have chosen the 12 months ended May 31, 1991, as suggested by the AG.

The Commission has a number of concerns. We are not persuaded that ULH&P's methodology is acceptable for rate-making purposes nor are we persuaded that it is appropriate for an

electric utility to attempt to normalize for weather while ignoring the other factors that affect energy usage. ULH&P contends that altering its method to separate loads into temperature-sensitive and non-temperature-sensitive components would introduce additional error into the normalization process; however, it did not support this contention nor did it consider whether such a separation might improve its determination of the level of weather normalized sales. ULH&P used its load forecasting model to derive its weather normalization adjustment and held all variables within the model, other than the weather variable, constant, or at actual test-year levels. This approach does not consider, or attempt to normalize, these other variables which is in direct opposition to a prior Commission opinion on this subject.[22]

The Commission has reviewed the applicable publications referenced by ULH&P concerning official weather normals as established by NOAA. Our review indicates that the 1951-1980 data is the most current official 30-year data available, as ULH&P claims. Our review also indicates that NOAA makes available sufficient information to enable someone to replicate that data or perform a comparable calculation for a different period of time. As indicated in other cases, the Commission considers it important

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22 Case No. 10064, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company, Order dated July 1, 1988.

that weather data be current.[23] ULH&P's normalization adjustment does not recognize the impact that temperatures in recent years might have on determining normal temperatures.

The Commission is also concerned about the accuracy of ULH&P's approach to calculating billing-degree days for its 21 billing cycles. In its calculation, ULH&P gives equal weight to each of the 21 billing cycles even though (1) the number of days in each billing cycle can vary from month to month and (2) the number of customers per class for each billing cycle is not available for comparison. This approach may not properly match customers' loads and their corresponding bills since each billing cycle has different beginning and ending dates with a specific number of degree days and a specific number of customers for each month of the year. Although ULH&P indicated other utilities had researched this matter and found the potential for greater accuracy from use of a more detailed weighting approach was not statistically significant, ULH&P had not made a similar independent determination. Absent such a determination, we are not persuaded that the equal weighting approach used by ULH&P is sufficiently accurate for use in the rate-making process.

ULH&P's proposed weather normalization adjustment is denied. This results in an increase of $1,526,929 to ULH&P's normalized revenues, and will impact ULH&P's adjusted purchased power cost, supra.

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23 Id.

Interruptible Credit - Newport Steel

As part of its revenue normalization calculation, ULH&P adjusted its revenues to reflect a full 12 months at the rates in effect at test-year end. One component of ULH&P's adjustment was the annualization of the interruptible credit to Newport Steel based on the terms of the 1991 service agreement between ULH&P and Newport Steel and the level of firm, curtailable, and interruptible demands designated by Newport Steel for the last month of the test year. The annualization of Newport Steel's interruptible credit reduces ULH&P's revenues by $1,521,275.

The AG made two proposals concerning the Newport Steel interruptible credit. The first proposal, that ULH&P's annualization adjustment be disallowed, is based on the AG's concerns about the terms of the service agreement, the lack of any showing that the interruptible nature of the Newport Steel portion of ULH&P's load is properly reflected in CG&E's allocation of costs to ULH&P, and questions of whether the test year includes a representative, forward-looking level of sales to Newport Steel consistent with the terms and conditions of the agreement. The AG's second proposal is that the Commission disallow any interruptible credits in ULH&P's rates since ULH&P is not a generator of electricity. The AG suggests that all contracts for interruptible power should be between CG&E (the generator) and the interruptible customer. In arguing for this proposal, the AG contends that the amount of the monthly credit, $4.45 per KW at present and $5.25 per KW proposed, is excessive and is not based

on the avoided cost of new generating capacity for CG&E, which supplies 100 percent of ULH&P's power requirements.

ULH&P and Newport Steel argued against the AG's proposals claiming that their service agreement was beneficial to ULH&P's ratepayers. Newport Steel, after calculating an avoided cost for CG&E of $7 per KW per month, opines that both the current and proposed credits are justified and that the difference between the credit and CG&E's avoided cost represents a savings, or benefit, to ULH&P's remaining customers. Newport Steel also opposed the AG's suggestion that CG&E contract directly with ULH&P's interruptible customers, maintaining that such an arrangement would unduly complicate the regulatory process by potentially involving three jurisdictions, Kentucky, Ohio, and the FERC, in the review of such contracts. Newport Steel did share the AG's concerns that CG&E's proposed allocation of costs to ULH&P at the wholesale level does not fully recognize the nature of Newport Steel's interruptible load. Newport Steel indicated that this problem could be remedied at the FERC level if the Commission was not able to address it in this proceeding and suggested the type of modification that CG&E could make to its cost allocation study.

The Commission is not persuaded that the amount of the credit is excessive, nor do we find that there has been established any link between the amount of the credit and CG&E's avoided cost of new capacity. The Commission will not revoke the agreement or direct ULH&P to forego entering into such agreements in the

future. The agreement, as executed, was approved by Commission Order dated April 4, 1991,[24] after an earlier version of the agreement had been rejected on September 27, 1990.[25] Such agreements, properly reflected in the rate-making process, can be of long-term benefit to ULH&P, Newport Steel, and ULH&P's other customers as well. In this instance, however, the Commission has two concerns as to whether this agreement has been properly reflected in the rate-making process.

The Commission's first concern is that the allocation of costs to ULH&P by CG&E does not properly reflect the interruptible nature of Newport Steel's load. The record reflects that CG&E's pending FERC application, based on a coincident peak cost allocation methodology, does not take into account the fact that Newport Steel can be interrupted other than at the time of CG&E's coincident peak. In approving the agreement, the Commission presumed that all aspects of Newport Steel's interruptible load would flow through to CG&E since it is CG&E, not ULH&P, which controls the capacity and determines when loads will be interrupted. Since the entire CG&E system benefits from the interruptible nature of Newport Steel's load, ULH&P's customers, representing only 15 percent of the system, should not bear the

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24 Case No. 91-076, A Service Agreement Between The Union Light, Heat and Power Company and Newport Steel Corporation.

25 Case No. 90-068, A Service Agreement Between The Union Light, Heat and Power Company and Newport Steel Corporation.

brunt of the agreement's cost in the form of lower revenues through increased demand credits.

Our second concern deals with the demand level for Newport Steel included in the test year. Newport Steel's average monthly demand during the test year was 55,000 KW. In Case No. 90-068, ULH&P indicated that, with the operation of a third furnace, Newport Steel's monthly demand was expected to increase by one-half to approximately 80,000 to 85,000 KW with a corresponding increase in demand charge revenues.[26] ULH&P also indicated that, even with the larger demand credits under the new agreement, its annual revenues from Newport Steel would increase to $10.5 to $12 million compared to $9 to $9.5 million without the new agreement.[27] ULH&P's test-year revenues from Newport Steel, based on the test-year average demand, were $9.3 million.[28] However, ULH&P failed to propose any adjustment to reflect the anticipated increases in demand and revenues from Newport Steel.

It is apparent that ULH&P's adjustment to increase Newport Steel's interruptible demand credit only recognizes one aspect of their new service agreement. It is also apparent that ULH&P's purchased power cost does not equitably reflect the interruptible

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26 Response filed June 9, 1990 to the Commission's Information Request - First Set, Item 16.

27 Id.

28 The Union Light, Heat and Power Supplement C(9), WPC-3.1e.

nature of Newport Steel's load. For these reasons, the Commission has adopted the AG's recommendation to disallow ULH&P's proposed adjustment to annualize Newport Steel's interruptible credits. Such a disallowance increases ULH&P's normalized base revenues by $1,521,275 which, in turn, produces an increase of $9,843 in ULH&P's normalized forfeited discount revenue.

Fuel Synchronization

ULH&P initially proposed an adjustment to reduce fuel ("FAC") revenues by $200,996 in an attempt to match, or synchronize, FAC revenues with FAC expense. ULH&P modified its adjustment to produce a revenue reduction of $41,332. Both adjustments reflect the 2-month billing lag built into the FAC.

The AG recommended that ULH&P's proposal to reduce FAC revenues be rejected and proposed to increase such revenues by $244,578 over the actual test-year level. The AG argued that the adjustment should be based on test-year revenue levels rather than revenues for a period 2 months beyond the test year.

The Commission will accept the AG's proposal. The AG's adjustment is consistent with the approach used by the Commission in ULH&P's last case and in numerous other cases. While there is a 2-month billing lag inherent in the FAC mechanism, ULH&P's revenue requirements are being determined based on a 12-month test period ended July 31, 1991. ULH&P's approach doesn't consider the FAC revenues for the test period, but rather, the revenues for the 12 months ended September 30, 1991, 2 months beyond the test period. The purpose of the AG's adjustment is to eliminate any over- or under-recovery of fuel costs within the test year from

the determination of revenue requirements. To achieve this purpose, the adjustment must be based on the fuel costs and fuel revenues reported during the test period upon which revenue requirements are being determined. This adjustment results in a $445,574 increase to ULH&P's normalized revenues.

Year-End Customer Adjustment

ULH&P proposed adjustments to increase revenues and purchased power costs by $283,687 and $244,063, respectively, based on the difference between the average number of customers served during the test year and the number of customers served as of the end of the test year. The increased KWH sales and increased KWH purchases included in the calculations reflected the impact of ULH&P's proposed weather normalization adjustment. The average cost per KWH as calculated by ULH&P reflected the projected increase in purchased power costs from CG&E.

Based on its proposal that ULH&P not be allowed to recover its increased purchased power costs, the AG argued that such costs should not be included in the calculation of the year-end customer adjustment. Based on this argument, the AG reduced ULH&P's year-end customer purchased power adjustment by $44,985.

The Commission has modified ULH&P's year-end customer adjustment to eliminate the impact of the proposed weather normalization adjustment from the calculations, consistent with our decision to reject the weather normalization adjustment. Based on actual test-year KWH sales and purchases, the increases to revenues and purchased power costs have been calculated to be $756,203 and $624,579, respectively.

Purchased Power Expense

ULH&P proposed an adjustment to increase its purchased power expense by $25,031,563. This adjustment reflected a proposed increase in CG&E's wholesale power rate, a reduction to ULH&P's purchased power volumes based on its proposed weather normalization adjustment and correction of a billing error in the last month of the test year. The increased wholesale power rate was allowed to go into effect February 13, 1992, subject to refund, pending final resolution of CG&E's rate case before the FERC.

The AG contends that the wholesale power contract between CG&E and ULH&P should be examined to determine whether ULH&P should have sought out other power suppliers. The AG argues that, while this Commission cannot rule on the reasonableness of CG&E's rate to ULH&P, it could find ULH&P's purchase from CG&E to be imprudent due to the existence of lower cost alternative power supplies. In support of this argument the AG cites a number of recent contracts for purchased power at rates less than those charged by CG&E. The AG goes on to argue that, as the contract between CG&E and ULH&P is a less-than-arm's length agreement and since ULH&P did not solicit bids from other suppliers, its purchase from CG&E is imprudent. The AG recommends that the Commission require ULH&P to solicit bids for other power supplies to ensure that customers' best interests are being served.

In addition to its bidding proposal, the AG opines that the Commission must deny ULH&P's requested adjustment on the grounds that it is not known and measurable. The argument goes that since the increased rate from CG&E is subject to refund pending the

FERC's final decision, the current rate is not permanent and will likely not be the final rate approved by FERC. The AG also questions whether this Commission can require ULH&P to make refunds to its customers of amounts refunded to ULH&P by CG&E in the event the FERC requires such refunds by CG&E.

ULH&P defended its decision to contract with CG&E for 100 percent of its power requirements. ULH&P opines that firm power, in the amount and quality required to meet its customers' needs, is not available in the region at a price less than the CG&E rate. ULH&P contends that power from other, further-away sources, while priced at rates comparable with CG&E, would incur wheeling charges that render it uneconomical.

ULH&P also claims that the AG's argument does not recognize all the additional costs ULH&P would incur to secure power from sources other than CG&E. Chief among these costs would be a capital investment of over $100 million for bulk power transmission facilities necessary for its own connections with other utilities. ULH&P also maintains that, under its contract with CG&E, it pays only for its monthly metered demand without incurring a minimum demand charge which it would incur if it were required to purchase power from another source.

ULH&P states that there is no reason for concern as to the protection of its customers in the event the FERC's final decision in the pending CG&E case produces a rate less than that allowed to go into effect February 13, 1992. ULH&P contends that any refund it receives from CG&E will, in turn, be refunded to its customers.

As the Commission stated in its December 13, 1991 Order, the FERC has exclusive jurisdiction to review and determine a reasonable rate for the sale of power to ULH&P. CG&E's request to increase the rate paid by ULH&P is intended solely to recover the substantial sums expended to convert the Zimmer Generating Plant ("Zimmer") from a nuclear to a coal-powered facility. Based upon our knowledge of the cost of Zimmer and the costs of comparable coal-powered generating plants, it is clear that the cost of Zimmer is excessive by at least 50 percent. Due to our lack of jurisdiction over CG&E's cost of Zimmer and the determination of a reasonable rate for power sales to ULH&P, we have intervened at the FERC and will vigorously oppose CG&E's attempts to recover unreasonable Zimmer costs from ULH&P.

The Commission is legally bound to accept as reasonable the purchased power rate as filed with the FERC and that filed rate must be recognized as a legitimate expense for retail rate-making purposes.[29] However, the courts have recognized a limited exception to this rule in situations where the affected utilities are not members of a regulated holding company. The exception allows a state commission to recognize in retail rates an amount less than the FERC filed rate if lower cost alternative power is available elsewhere.

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29 Mississippi Power and Light Co. v. Mississippi, ex rel. Moore, 487 U.S. 354 (1988).

In this case, the Commission can make no finding that lower cost alternative power is actually available. Even though we believe the cost of Zimmer to be excessive, the FERC filed rate is a composite rate which reflects the costs of all of CG&E's generating units, not just Zimmer. While the AG has alleged the existence of lower cost supplies, ULH&P has effectively refuted the allegations. The record shows the potential supplies identified by the AG to be either inferior in quality, i.e. less than firm power, or higher in price than the power ULH&P obtains from CG&E. Since ULH&P owns no generating facilities of its own, any power purchases must be of firm power which is available 24 hours per day, year round, in the contracted for quantities. The record is devoid of any credible evidence that a lower cost alternative supply is actually available. Absent this evidence, the Commission can make no finding that the FERC filed rate is unreasonably excessive in light of alternative power supplies.

The AG's contention that ULH&P's adjustment to increase purchased power expense is not known and measurable is unfounded. The rate ULH&P is being charged by CG&E has been accepted by, and is on file with, the FERC. This FERC filed rate is both known and measurable albeit potentially temporary in nature. As an intervenor in CG&E's pending case before the FERC, the Commission will be well aware of both the timing and magnitude of any reduction in CG&E's filed rate and will take the steps necessary to ensure that ULH&P's customers receive any refunds due them. The rates granted herein will be subject to refund pending a final decision by the FERC on CG&E's wholesale power rate.

The increase proposed by ULH&P has been modified to eliminate the impact of its proposed weather normalization adjustment. The modified increase, on a Kentucky jurisdictional basis, is $25,598,523.

Labor and Labor-Related Costs

ULH&P proposed adjustments to increase the test-year operating expenses by $233,378 for labor and labor-related costs. The actual cost items and the proposed adjustments to electric operations are as follows:

	Total
Wages and Salaries	$ 227,411
SIP & DCIP Plan Costs	3,184
FICA Taxes	2,783
	$ 233,378

Wages and Salaries. ULH&P proposed to increase wages and salaries by $227,411, to reflect the annualization of base wage increases granted to all employee groups during the test year. ULH&P calculated the adjustment by multiplying the average hourly wage increase by the number of hours charged to the electric operations, and then annualizing the result by the appropriate number of months.

ULH&P provided a series of workpapers which documented the hours worked during the test year by ULH&P employees for ULH&P activities.[30] The labor hour allocation process used by ULH&P and

[30] Application Workpapers WPC-3.4d through WPC-3.4o, also summarized as Staff Cross-Examination Exhibit No. 1 - Bruegge.

CG&E also includes the determination of hours worked by CG&E or other subsidiary employees for ULH&P activities and the hours worked by ULH&P employees for CG&E or other subsidiary activities. Documentation of these hours was not provided by ULH&P.

ULH&P provided a workpaper showing the allocation of hours worked by bargaining groups and account distribution for the month of May 1991. ULH&P bases its annual allocation of labor hours on the distributions developed from May data. This allocation process assigns hours to gas or electric operations, construction work in progress, retirement work in progress, work performed by other CG&E employees for ULH&P (referenced as accounts payable), and work performed by ULH&P employees for CG&E (accounts receivable).[31] While ULH&P has based its annual allocation on the activity in the month of May for many years, there has not been any verification undertaken by ULH&P to determine that May is the most representative month to use.[32]

The allocation percentages used in the May labor analysis are based on annual time studies. The time studies related to unionized labor groups usually are documented by work orders. The time studies for supervisory, administrative, and professional employees are based upon an annual study performed in October.

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31 Application Workpaper WPC-3.4b.

32 T.E., Vol. II, March 18, 1992, pages 44 and 45.

The hours reported in the study for this group are not based on the actual work performed in that month, but rather reflect what ULH&P purports to be a more "representative" or "normal" month.[33]

In reviewing the evidence provided by ULH&P concerning its labor hour allocation process, the Commission is concerned about several issues. First, the only allocation which should be needed for the hours worked by ULH&P employees for ULH&P activities would be between gas or electric operations, construction work in progress, and retirement work in progress. However, in determining the hours used in the wage normalization, the test-year actual hours worked by ULH&P for ULH&P were also allocated to the accounts payable and accounts receivable categories.

In reviewing the May labor hour allocations, the hours shown on that workpaper could not be matched or reconciled with the hours represented to be the actual hours worked by ULH&P for ULH&P for the month of May 1991. In the 1989 Management and Operations Review of ULH&P, the management auditors expressed concern about the time documentation process used in the supervisory, administrative, and professional group's time studies and recommended alternative methods be reviewed to develop more reliable means of gathering time data.[34] Furthermore, the Uniform

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33 T.E., Vol. III, March 19, 1992, page 254; T.E., Vol. II, March 18, 1992, pages 44 and 45.

34 Management and Operations Review of The Union Light, Heat and Power Company, August 1989, pages 54 and 60.

System of Accounts for Electric and Gas Utilities ("USoA") requires that the distribution of employee wages "[s]hall be based upon the actual time engaged in the respective classes of work, or in case that method is impracticable, upon the basis of a study of the time actually engaged during a representative period."[35]

The Commission is not opposed to the concept of wage normalization. However, the problems we have noted concerning labor hour documentation and allocation make it impossible to verify the reasonableness of the proposed wage normalization adjustment. Therefore, the Commission must reject the $227,411 adjustment proposed by ULH&P. As recommended by the management auditors, the Commission instructs ULH&P to conduct a thorough review of its labor hour allocation and documentation processes and bring it into conformity with the requirements outlined in the USoA. This will require ULH&P to change the supervisory, administrative, and professional group's time study to one which is based on actual time worked. It will further require that ULH&P determine what is a representative period, which may include more than one month of a year.

Savings Incentive Plan ("SIP") and Deferred Compensation and Investment Plan ("DCIP"). ULH&P proposed an increase of $3,184 for its SIP and DCIP. Executive, supervisory, administrative, and professional employees can participate in DCIP, while all other employees of ULH&P can participate in SIP. ULH&P determined the

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35 Uniform System of Accounts, Publication Number FERC-0114, General Instructions, No. 4.

increase by applying a cost factor to its proposed wage normalization adjustment. ULH&P stated that as wages increase, its contributions to the SIP and DCIP would also increase.[36] The AG opposed the inclusion of any costs associated with the DCIP, citing the current state of the economy and the size of ULH&P's proposed rate increase.[37]

The Commission is not persuaded to remove all costs of the DCIP. These types of fringe benefits are commonly provided by major utilities and there is no valid reason why such benefits should be denied to one class of ULH&P's employees and allowed for another. We have determined that ULH&P's contributions to the plans are a function of three independent factors: the number of employees enrolled in the plans; the amounts contributed by participating employees; and ULH&P's required matching contribution rate, which is limited to the first 5 percent of the participating employee's base pay.[38] Given these factors, it is inappropriate to calculate an increase for these contributions by simply applying a cost factor to the proposed wage normalization. Based on this finding, and the above finding to reject the

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36 Response to the Commission's Order dated December 17, 1991, Item 31.

37 DeWard Direct Testimony, pages 22 and 23.

38 Response to the Commission's Order dated November 14, 1991, Items 45(a) and 45(p).

proposed wage normalization adjustment, the Commission has not included the proposed increase in the costs of the SIP and DCIP.

FICA Taxes. ULH&P proposed to increase its FICA taxes by $2,783. The increase reflected changes in the FICA applicable base wage and tax rates which became effective January 1, 1991. The proposed adjustment was calculated on the 1990 calendar year wages and did not reflect the impact of wage increases granted between January 1991 and the test-year end.

In Case No. 90-041, the Commission expressed concern about ULH&P's presentation of wage adjustments and payroll tax adjustments based on different time periods. Using different time periods for these types of adjustments is inherently unreliable and inaccurate. ULH&P was instructed that, in future cases, adjustments to wages and salaries and payroll taxes should reflect the same time periods.[39] Despite this instruction, ULH&P has again presented these adjustments based on different time periods. Due to the improper calculation of the proposed adjustment to FICA taxes, the adjustment must be rejected.

Key Employee Annual Incentive Plan ("KEAIP"). The AG proposed to remove all test-year costs associated with the KEAIP. The AG included this proposal with this recommendation to remove all costs related to the DCIP. The amount the AG proposed to exclude contained test-year costs for both electric and gas operations.

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[39] Case No. 90-041, Order dated October 2, 1990, page 31.

Based on a thorough review of the KEAIP provisions, the Commission will exclude these expenses for the following reasons. First, while the plan does include so-called protection clauses for both customers and shareholders, the plan narrative clearly states that, "The Board, the Compensation Committee, and management all agree that the interests of shareholders must be paramount and protected when considering the appropriateness of any compensation program for key employees."[40] The Commission believes that, for a utility, the interests of the shareholders and the customers should be balanced and protected.

Second, in reviewing the performance objectives for calendar years 1990 and 1991, the 1991 performance objective targets were reduced only in those areas where in 1990 ULH&P and CG&E key employees had failed to reach the target.[41] ULH&P explained that some of these reduced targets were related to the fact that ULH&P and CG&E were going to be involved in rate cases during 1991.[42] However, in 1990 ULH&P was involved in a rate proceeding and it would not seem reasonable that pending cases in 1991 would be the sole reason to reduce performance objective targets. Finally, the Commission has carefully examined the evidence concerning the

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40 Response to the Commission's Order dated December 17, 1991, Item 60, page 2 of 4.

41 Response to the Commission's Order dated January 17, 1992, Item 43(d) and 43(e).

42 T.E., Vol. III, March 19, 1992, pages 216 and 217.

compensation and benefits available to these key employees. It appears that key employees received salary increases in addition to KEAIP payments[43] and that the overall benefits package, exclusive of the KEAIP payments, is quite adequate.[44]

The test-year expenses for KEAIP should not be included for rate-making purposes and electric operating expenses are reduced by $26,201.

Executive Severance Agreements. Included with the AG's proposal to remove the test-year expenses for DCIP and KEAIP was the removal of $166 of test-year expenses for executive severance agreements. The Commission has searched the record and is unable to find any evidence that the ratepayers were charged for executive severance agreements. We do note, however, that the expenses for the supplemental executive retirement plan were not included in this electric rate case.[45] Due to the minuscule amount of this proposed adjustment and the absence of verification that it was included in the test year, no adjustment to operating expenses will be made.

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43 Response to the Commission's Order dated November 14, 1991, Item 37.

44 Response to the Commission's Order dated December 17, 1991, Item 58.

45 Response to the AG's Supplemental Data Request, Item 44.

Meter Reading Workforce Reduction. The 1989 Management Audit Report included a recommendation that ULH&P undertake a re-routing of its meter reading routes. Although the work on this recommendation is still in progress, ULH&P indicated that it had already realized a reduction in the meter reading workforce of four employees, resulting in an annual wage savings of $125,000.[46] ULH&P proposed no adjustment to the test-year operations to reflect this savings.

It is appropriate to reflect these savings and accordingly test-year operating expenses have been reduced by $125,000.

Overtime Labor. In Case No. 90-041, the Commission expressed its concern over the increased levels of overtime hours incurred by ULH&P. In this case, ULH&P included a schedule showing the test-year actual and five previous calendar years' level of overtime hours.[47] This schedule shows that, with the exception of 1989, the level of overtime hours has been steadily increasing. ULH&P was asked to describe the steps taken by it and CG&E to control the level of overtime hours. However, ULH&P only responded that it had taken steps to utilize employees to the maximum effort possible, and provided no specific actions taken.[48]

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46 Response to the Commission's Order, dated January 17, 1992, Item 66(c).

47 Schedule C-11.1 of the Application.

48 T.E., Vol. III, March 19, 1992, page 237.

ULH&P has failed to recognize the ever increasing level of expense associated with overtime. No study or analysis has been performed to determine an optimal level of overtime or an optimal workforce level. Therefore, the Commission will reduce the overtime labor expense to reflect the historic average of overtime labor hours. We believe this approach results in a more reasonable level of expense under the circumstances in this case and have reduced operating expenses $74,287, as determined in Appendix C.

The Commission is also concerned by ULH&P's allocation of overtime labor hours. The overtime labor hours are converted to equivalent regular labor hours and allocated to the same accounts as the regular hours, regardless of the source of the overtime hours. ULH&P has performed no analysis to support the assumption that overtime labor hours should be allocated on the same basis as the regular labor hours. There is no evidence to demonstrate that ULH&P's current practice results in a reasonable allocation. The Commission will require ULH&P to modify its overtime labor hour allocation procedures in order that overtime will be allocated to the source of that overtime.

Labor Study. In Case No. 90-041, the Commission instructed ULH&P to provide a thorough analysis of its staffing levels with its next general rate case.[49] ULH&P did not provide or perform such an analysis. ULH&P indicated that it had not planned to file this

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[49] Case No. 90-041, Order dated October 2, 1990, page 34.

rate case and that it was not prepared to comply with the Commission's instructions.[50] In the 1989 Management Audit Report, several labor-related areas were identified as needing the attention of ULH&P.

The Commission is concerned about the numerous labor-related issues which have come to our attention during this proceeding. We believe the record clearly indicates that ULH&P must affirmatively address issues concerning its labor needs as part of the integrated CG&E system, the management of overtime hours, the reasonableness of current assumptions concerning spans-of-control, and all other management audit recommendations focusing on labor-related issues. The Commission expects that by the next general rate case, ULH&P will have taken appropriate constructive action on all of these issues. The Commission will evaluate the prudency of all ULH&P responses regarding labor and labor-related costs.

Uncollectible Accounts

As in past cases, ULH&P included in its requested revenue increase a commensurate increase in its provision for uncollectible accounts based upon its test-year provision for uncollectibles viewed as a percentage of total revenues. ULH&P used a test-year provision for uncollectibles, as a percentage of

50 T.E., Vol. IV, March 20, 1992, page 71.

total revenues, of 1 percent.[51] However, this percentage reflected the blended provision for both gas and electric operations. The test-year electric provision for uncollectibles was .95 percent.[52] The Commission accepts ULH&P's methodology of adjusting uncollectible accounts, but will apply the test-year electric provision percentage rate to the revenues as adjusted in this Order. The Commission will determine ULH&P's revenue requirement using .95 percent to reflect the increase in uncollectible accounts expense associated with the revenue increase granted herein.

PSC Assessment

ULH&P included in its requested revenue increase a commensurate increase in the expense for the PSC Assessment, based upon the assessment rate in effect during the test year. The Commission accepts this proposal and has normalized the assessment based on the normalized revenues as adjusted in this Order. The Commission will include the PSC Assessment rate in the determination of ULH&P's revenue requirement.

Charitable Contributions

As it has in its three previous cases, ULH&P proposed an adjustment to increase operating expenses by $88,576 to reflect the expense for charitable contributions made during the test

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51 Application Workpaper WPC-12a.

52 Response to the Commission's Order dated December 17, 1991, Item 46.

year. While ULH&P acknowledged that the Commission has not recognized this adjustment in past decisions, ULH&P stressed that this is a necessary business expense which is a response to the needs and desires of the community.[53] However, ULH&P presented no new evidence, not previously considered by the Commission, to support this adjustment. The AG opposed the proposed adjustment, citing past Commission practice to deny such expenses.

The Commission has consistently excluded donations for rate-making purposes because the expense is not related to the provision of utility service. Donations enhance a utility's corporate image and are properly borne by the shareholders. ULH&P has failed to persuade us to include the expense in this case.

Rate Case Expenses

ULH&P proposed to adjust operating expenses by $50,000 to reflect its estimate of the entire cost of this rate case. Although no expenses related to this case were included in the test year, $17,968[54] related to Case No. 90-041 was included in the test year.

Throughout this proceeding, the Commission required ULH&P to provide the current actual rate case cost, with adequate supporting documentation. ULH&P was opposed to an ongoing filing

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53 Bruegge Direct Testimony, page 9.

54 Schedule C-10 of the Application.

but agreed to file its last updated actual rate case cost 20 calendar days after the completion of the public hearing.[55] The public hearing was completed on March 23, 1992, making the last update due April 12, 1992. ULH&P filed its last update with the Commission on April 22, 1992. The last update contained costs which were inadequately documented. Therefore, the Commission has rejected the April 22, 1992 filing and will use the cost information from the March 4, 1992 response as the basis for its adjustment. The actual rate case costs filed on March 4, 1992 totaled $35,742.

It would not be reasonable for ULH&P to recover the costs of this rate case every year that the rates established herein are in effect. It also would not be reasonable to use an estimated cost when the actual cost is known. The Commission believes it is appropriate in this case to amortize $35,742 in actual costs over a 3-year period, or an annual amortization of $11,914. The test-year expenses for Case No. 90-041 should be removed from operating expenses, resulting in a net reduction in operating expenses of $6,054.

Amortization of Management Audit Cost

ULH&P proposed to increase operating expenses $51,385 to reflect the annual amortization of its management audit costs. In

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55 Response to the Commission's Order dated January 17, 1992, Item 46.

Case No. 90-041, the Commission approved ULH&P's proposal to amortize $257,067[56] in management audit costs over a 3-year period. At the end of the suspension period in this case, 17 months or $121,407[57] would remain to be amortized. At the present amortization rate, ULH&P would recover the cost by October 1993.

ULH&P is entitled under the management audit statute to recover the total cost of the management audit but it is not entitled to recover in excess of its cost. Thus, to avoid over-recovery, the amortization rate should be adjusted. The annual amortization rate for rate-making purposes should be $40,464 based on a 3-year amortization of the unamortized cost through the end of the suspension period. The electric portion of the revised amortization is 60 percent, or $24,278. Therefore, the Commission has increased operating expenses by $24,278.

Depreciation Expense

ULH&P proposed to increase depreciation expenses by $218,909. The adjustment reflected the normalization of depreciation expense on utility plant in service at test-year end. The AG proposed to reduce the normalized expense by $204,000 to reflect the over-depreciation of overhead street lighting plant.[58] The

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56 Case No. 90-041 Application Workpapers WPC-3.6a.

57 $257,067 multiplied by (17 months / 36 months).

58 DeWard Direct Testimony, page 31.

Commission has reviewed the utility plant information and has determined that the overhead street lighting account was fully depreciated at test-year end.[59] ULH&P has stated that it would stop depreciating the account at the time the net plant is zero.[60]

The Commission has included only $14,909 of the depreciation expense adjustment proposed by ULH&P. This adjustment has been included in the accumulated depreciation used to determine the jurisdictional electric net original cost rate base. This has been the Commission's traditional practice concerning depreciation expense adjustments.

Interest Synchronization

ULH&P proposed to adjust its interest expenses used in computing state and federal income taxes. ULH&P's approach was to apply the weighted cost of long-term debt to its rate base. The test-year actual interest expense was deducted from this amount to arrive at the adjustment to interest expense for the computation of income taxes.

Historically, for rate-making purposes, the Commission has imputed interest expense on the portion of JDIC assigned to the debt components of the capital structure and treated the interest as a deduction in computing the income tax expense allowed in the cost of service. The revenue requirements in this proceeding are

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59 Schedule B-3 of the Application, page 2 of 4.

60 T.E., Vol. I, March 17, 1992, page 176.

being determined from the capitalization rather than the rate base; therefore, the Commission believes its previous practice is more appropriate in determining the interest synchronization. This was the same approach used by the Commission in previous ULH&P general rate cases. The Commission has applied the applicable cost rates to the JDIC allocated to the debt components of the capital structure. ULH&P's interest expense applicable to Kentucky jurisdictional operations during the test year was $4,465,702. Using the adjusted capital structure allowed, the Commission has computed an interest expense reduction of $172,469, which results in an increase to income tax expense of $68,029.

Storm Damages

ULH&P proposed an adjustment of $6,934 to increase its expenses for storm damages to reflect the 10-year average expense. The adjustment was calculated using the June 1991 Consumer Price Index-Urban ("CPI-U") to adjust the recorded dollar amount to July 31, 1991. Such an adjustment is consistent with the Commission's decisions in previous ULH&P rate cases; however, the Commission believes that it is more appropriate to use the July 1991 test-year end CPI-U. The Commission has recalculated the adjustment using the appropriate CPI-U for the test year and has determined that operating expenses should be increased $7,075.

Injuries and Damages

ULH&P proposed an increase of $57,080 to its expenses for injuries and damages to reflect the 10-year average expense. The adjustment was calculated using the same methodology as had been used in the adjustment for storm damages. Because the Commission

believes it is more appropriate to use the test-year end CPI-U for July 1991, we have recalculated the proposed adjustment, increasing operating expenses by $57,313.

Postage Expense

ULH&P proposed an increase of $17,731 to its operating expenses to reflect postage rate increases effective February 3, 1991 on an annual basis. ULH&P computed the increase by annualizing the cost of the test-year level of mail and then subtracting the actual mailing costs which reflected the period from February 3 through test-year end.

The Commission cannot accept the adjustment as proposed by ULH&P. In performing its calculations, ULH&P ignored the postage costs which were incurred at the old rates from the beginning of the test year until February 2, 1991. In effect, this adjustment contains a double count of postage expense for 6 months of the test year. We therefore reject the proposed adjustment.

The Commission also notes that the majority of mailings included in the proposed adjustment related specifically to ULH&P, such as customer bills and first class letters. ULH&P has indicated that its costs for these items are allocated to ULH&P by CG&E. The Commission does not believe it is appropriate for such mailing costs to be allocated when they should reflect direct charges. Customer bills and other ULH&P mailings must be specifically identified and directly charged to ULH&P's accounts rather than allocated.

Advertising Expenses

ULH&P proposed an adjustment to reduce operating expenses by $127,821 to reflect the elimination of institutional advertising as required by 807 KAR 5:016, Section 4. The charges eliminated represented the test-year-end balances of Account No. 913, Advertising Expenses, and Account No. 930.1, General Advertising Expenses. While making the adjustment in compliance with the regulation, ULH&P claimed that these expenses are necessary, recoverable business expenses, and should not be eliminated.[61] This position is the same one taken by ULH&P in Case No. 90-041.

In addition to ULH&P's adjustment, the AG proposed to remove the following additional expenses:

Customer Service & Information:	
Account No. 907 - Supervision	$ 69,211
Account No. 908 - Customer Assistance Expenses	766,201
Sales:	
Account No. 911 - Supervision	20,371
Account No. 912 - Demonstrating and Selling Expenses	171,110
Total	$1,026,893

The amounts for Accounts No. 907, 911, and 912 represent the entire test-year charges. The AG contends that these expenses are not appropriate for inclusion in rates because they reflect a massive effort by ULH&P to market its product without any cost justification.[62]

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61 Bruegge Direct Testimony, page 13.

62 DeWard Direct Testimony, page 24.

The Commission has been able in this proceeding to review with greater detail the advertising expenses of ULH&P than was available in Case No. 90-041. Some of the expenses recorded in Account No. 912 appear to be promotional in nature and are not allowable under 807 KAR 5:016. In addition to the advertising expense adjustment proposed by ULH&P, the Commission has reduced operating expenses by $66,779. This amount reflects the test-year charges to Account No. 912-40, Regional Marketing - Central Division; Account No. 912-41, Regional Marketing - Southern Division; Account No. 912-42, Regional Marketing, Planning & Community Development; and $5,833[63] in other specific Account No. 912 transactions.

AFUDC

ULH&P proposed an increase in revenues of $735,395 to reflect its annualization of AFUDC related to construction work in progress ("CWIP") subject to AFUDC as of test-year end. ULH&P computed its adjustment taking the electric CWIP subject to AFUDC and multiplying that amount by the AFUDC rate of 9.5 percent.[64]

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63 $3,472 - Dektas & Eger, Inc., trade magazine ads; $1,499 - Associated Premium Corp., jar openers; and $862 - Community Profiles.

64 Response to the Commission's Order dated November 14, 1991, Item 33, page 43 of 43.

The AG proposed to remove ULH&P's book taxes associated with AFUDC, stating that without such an adjustment, tax expenses would be duplicated because of ULH&P pro forma adjustment.[65]

The methodology followed by ULH&P closely parallels that used by the Commission in determining an AFUDC offset to net operating income. However, ULH&P's approach used the AFUDC rate instead of the overall rate of return on capital and did not adjust the increase for the test-year-end electric balance in Account No. 432, AFUDC - Credit. An AFUDC offset adjustment consistent with previous ULH&P cases results in a more reasonable overall rate of return. ULH&P's net operating income is increased by $629,478 to reflect pro forma AFUDC of $782,361[66] for rate-making purposes.

Demand Side Management ("DSM") Incentive Payment

The AG proposed to remove a test-year incentive payment of $38,025 made by ULH&P relating to a customer's installation of a thermal energy storage system. The AG indicated that the installation was not completed during the test year, and there were no offsetting benefits associated with reduced demand or reductions in allocated costs. Therefore, in his view, it was inappropriate to include this cost for rate-making purposes.[67]

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65 DeWard Direct Testimony, page 31.

66 $7,741,000 times 10.107% = $782,361.

67 DeWard Direct Testimony, page 25.

When asked if the test-year level of expense for all DSM activity reflected the normal, ongoing level of expense, ULH&P could not indicate whether the level would be higher, lower, or the same.[68]

The Commission realizes that ULH&P's DSM involvement is in its early developmental stages. The Commission encourages ULH&P in its DSM efforts. However, it must be displayed that some indication of expected ongoing levels of activity or similar incentive payments will be a recurring DSM expenditure. Operating expenses have been reduced by $38,025.

Hartwell Recreation Center ("Hartwell")

The AG proposed to reduce operating expenses $30,759 for operation and maintenance and rental charges associated with Hartwell, which is owned by CG&E. The AG stated that the Commission had removed similar expenses in Case No. 90-041 and that there was no reason to reverse that decision given the current economic situation.[69]

ULH&P indicated that the facility was used for training programs, recreational programs, and employee gatherings such as the annual Christmas party. While ULH&P stated that there were benefits to the ratepayers in having Hartwell, it could not quantify those benefits.[70]

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68 T.E., Vol. III, March 19, 1992, page 183.

69 DeWard Direct Testimony, page 26.

70 T.E., Vol. II, March 18, 1992, pages 149 through 152.

We do not believe the costs to maintain recreation centers should be included for rate-making purposes. While these expenses may benefit employer/employee relations, the ratepayers should not bear these costs. Operating expenses have been reduced by $30,759.

Special Programs

The AG proposed to remove from operating expenses $39,019 related to numerous management training, assessment, and enhancement programs. The AG stated that given the current economic conditions, such programs were not needed to motivate ULH&P employees. The AG also argued that any incurred costs from these programs should be offset by future efficiencies.[71]

In order to be effective, a utility may need to undertake numerous types of training programs. Current economic conditions do not necessarily represent a positive motivating force to encourage a workforce. No adjustment is required.

Edison Electric Institute ("EEI") Dues

The AG proposed to remove $50,993 from operating expenses for EEI membership dues. The AG stated that EEI is an electric utility lobbying organization, whose primary interest is protection of shareholders.[72]

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71 DeWard Direct Testimony, pages 26 through 28.

72 Kinloch Direct Testimony, pages 62 through 65.

ULH&P indicated that it had not performed any cost/benefit analysis for the EEI dues. Further, ULH&P could not identify any specific benefits it or its ratepayers received from membership.[73]

The Commission is familiar with EEI and aware of the nature of its activities. We have excluded EEI membership dues in other rate proceedings when ratepayer benefit could not be demonstrated. Given the nature of EEI and ULH&P's lack of demonstrating ratepayer benefit of membership, the Commission has removed from operating expenses the allocated membership dues of $50,993.

Electric Power Research Institute ("EPRI") Membership Dues

The AG proposed a reduction in operating expenses of $601,136 for ULH&P's allocated share of membership dues in EPRI. The AG noted that ULH&P had not performed any cost/benefit analysis of its membership. The AG stated that since ULH&P was a distribution utility, the majority of EPRI research was of no direct benefit to ULH&P's ratepayers.[74]

As with EEI, the Commission is aware of the nature of EPRI's activities. We recognize that EPRI is a research organization funded by membership dues paid by member utilities. Applied EPRI research in generation, transmission, and distribution fields should be of benefit to ULH&P and its ratepayers, regardless of whether ULH&P is a generator or distributor. No adjustment is required.

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[73] T.E., Vol. III, March 19, 1992, pages 184 and 189.

[74] Kinloch Direct Testimony, pages 67 and 68.

Hay Associates

During the test year, ULH&P was allocated $1,731 in expenses related to Hay Associates.[75] Hay Associates performs annual reviews of ULH&P's and CG&E's salary structure.[76] ULH&P has indicated that Hay Associates does not submit written reports of its analysis.[77] While Hay Associates does maintain a utility salary data base, ULH&P also indicated that a significant amount of salary information used in the annual evaluation of salary structure was maintained in-house.[78] It is not clear what the function of Hay Associates is, and ULH&P has not adequately documented the benefit from the services provided by Hay Associates. Operating expenses are reduced by $1,731 to exclude this expense for rate-making purposes.

Employee-Related Expenses

The AG proposed to reduce expenses by $42,625 for items recorded in Account No. 926, Employee Pensions and Benefits. The AG stated that these expenditures represented inappropriate costs to include for rate-making purposes.[79] ULH&P responded that the

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75 Response to Staff Hearing Data Request No. 8.

76 Response to the Commission's Order, dated January 17, 1992, Item 68(d).

77 Id., Item 68(a).

78 T.E., Vol. IV, March 20, 1992, pages 115 through 117.

79 DeWard Direct Testimony, page 25.

charges to Account No. 926 were necessary to maintain good employee morale, which translated into good customer service.

As shown in Appendix D, expenses for employee picnics, children's Christmas parties, and charitable fund-raisers should not be included for rate-making purposes, reducing operating expenses by $2,572.

Miscellaneous Expenses

The AG proposed to reduce expenses by $65,142. This amount included $12,258 for a Christmas train display in CG&E's main office and $52,884 in miscellaneous expenditures. The AG argued that the train display only promoted the image of CG&E and had nothing to do with providing reliable electric service. The AG stated that the other miscellaneous expenses included items previously disallowed in Case No. 90-041 and expenses which appeared to have been misclassified as operating expenses rather than properly as donations.[80]

ULH&P claimed that the AG's adjustment eliminates expenses which are responsible for the efficient and reliable services provided by it to the community. ULH&P believes that these expenses are reasonable and necessary and should not be eliminated.[81]

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80 DeWard Direct Testimony, pages 28 through 30.

81 Lonneman Rebuttal Testimony, page 11.

It appears that several expenses that ULH&P has recorded on its books as operating expenses should have been recorded in Account No. 426.1, Donations. Several miscellaneous expenses identified by the AG are expenses we have disallowed in previous rate cases. The Commission has also identified other expenses that are not appropriate for rate-making purposes, including non-recurring items. A listing of the disallowed expenses totalling $69,032 is included in Appendix D. ULH&P shall review its accounting treatment of sponsorships and community programs and bring that treatment into compliance with the USoA's definition of Account No. 426.1.

The Commission, after consideration of all pro forma adjustments and applicable income tax effects, has determined ULH&P's adjusted net operating income to be as follows:

Operating Revenues	$148,824,021
Operating Expenses	153,832,122
AFUDC Offset	629,478
Net Operating Income	$(4,378,623)

RATE OF RETURN

Capital Structure and Debt Cost

ULH&P proposed to use its capital structure as of July 31, 1991 adjusted to include short-term debt and deferred investment tax credits.[82] The proposed capital structure included 48.80

82 Mosley Direct Testimony, page 5.

percent long-term debt, 3.21 percent short-term debt, and 47.99 percent common equity.[83] ULH&P's long- term debt component was based on the carrying value of debt. The AG proposed to base long-term debt on the outstanding principal amount. The AG's position was that this method more accurately states the true liability of the company and is supported by return on rate base regulatory theory.

ULH&P's use of the carrying value is more appropriate. The carrying value reflects the unamortized debt discounts, premiums, and expenses at the date of calculation. This adjusted value more closely matches the current booked costs to ULH&P as opposed to the ultimate liability, and it is the booked costs that are appropriate to use in setting rates.

The cost of capital should be based on ULH&P's actual capital structure at July 31, 1991 consisting of 46.94 percent long-term debt, 7.11 percent short-term debt, and 45.95 percent common equity.

ULH&P proposed cost of long-term debt of 9.38 percent and cost of short-term debt of 7.58 percent based on an embedded cost of 9.27 percent as of July 31, 1991.[84] ULH&P updated its embedded cost of debt to December 31, 1991 reflecting long- term debt cost

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83 Calculated from ULH&P Exhibit JRM, pages 1-2, filed November 18, 1991.

84 Calculated from ULH&P Exhibit JRM, page 2, filed November 18, 1991.

of 9.375 percent and short-term debt cost of 5.935 percent.[85] Consistent with his recommendation on the debt component of capital structure, the AG calculated the cost of debt using average yield and yield to maturity. Consistent with ULH&P's determination of the debt component of capital structure its debt cost was calculated using interest expense less current amortization of debt discounts, premiums and expenses. As ULH&P's calculation more closely matches booked cost, we find the cost of long-term debt to be 9.375 percent and the cost of short-term debt to be 5.935 percent.

Return on Common Equity

ULH&P proposed a return on equity ("ROE") of 13.7 to 14.2 percent in its application.[86] ULH&P later determined its cost of common equity to be in the range of 13.4 to 13.9 percent.[87] The AG proposed the cost of common equity to be within the range of 10.25 to 11.25.[88]

To arrive at its requested return, ULH&P performed a discounted cash flow ("DCF") analysis and a risk premium analysis.

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85 Calculated from Revised ULH&P Exhibit JRM, page 2, filed March 17, 1992.

86 Mosley Direct Testimony, page 23.

87 T.E., Vol. I, March 17, 1992, page 125.

88 Weaver Direct Testimony, page 38.

For its DCF study ULH&P developed a proxy group of publicly traded utility companies to estimate its cost of equity as if it were a publicly traded independent company. ULH&P selected its proxy from combined gas and electric utilities reported in Value Line with bond ratings equivalent to ULH&P (BBB). ULH&P believes the proxy group is viewed by the financial community and investors as comparable risk companies.[89]

The DCF formula used by ULH&P reflects quarterly compounding of dividends and a 3.5 percent flotation cost adjustment.[90] ULH&P calculated an historical dividend growth rate of 6.7 percent for the period 1986-1990 and a projected dividend growth rate of 4.3 percent for 1994-1996. ULH&P concluded that a 5 percent growth rate is reasonable based on past and projected performance.[91] Based on stock prices for the 12 months ended February 29, 1992, ULH&P's DCF analysis produced a required ROE of 13.4 percent.[92] ULH&P concluded that it was more risky than its proxy and added a premium of 50 basis points to its DCF results to compensate for the difference in risk.[93]

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89 T.E., Vol. I, March 17, 1992, page 170.

90 *Mosley Direct Testimony*, page 10.

91 Id., page 17.

92 Revised ULH&P Exhibit JRM, page 4, filed March 17, 1992.

93 Mosley Direct Testimony, page 20.

ULH&P's risk premium analysis was based on a study by the Financial Analysts Research Foundation (updated by Ibbotson Associates, Inc.) on total rates of return for common stocks and bonds and the difference in average annual returns for the period 1926-1990. The study indicated an historical equity-debt risk premium of 4.9 percent.[94] To this, ULH&P added the current yield on its BBB rated bonds of 9.3 percent to arrive at a return on equity of 14.2 percent. ULH&P concluded that this result substantiates its DCF analysis.[95]

To perform a DCF analysis, the AG selected six companies he considered to be comparable to ULH&P. The AG determined his proxy group as combination gas and electric companies reported in Value Line with over 50 percent of revenues from electric and no nuclear facilities.

The AG averaged historical and forecasted rates to arrive at a growth rate of 3.25 to 4.25 percent for use in his DCF study. Based on stock prices for the period from October 18, 1991 - January 17, 1992 and adjusted for a 3.5 percent flotation cost adjustment, the AG's DCF study resulted in a cost of equity for ULH&P in the range of 9.86 to 10.92 percent.[96] Acknowledging an increased cost of equity to ULH&P due to lower interest coverage

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94 Id., page 18.

95 Id., page 19.

96 Weaver Direct Testimony, page 37.

than the comparable companies, the AG added a risk adjustment to arrive at his ultimate conclusion that the cost of equity to ULH&P is between 10.25 and 11.25 percent.[97]

Use of the quarterly dividend model for ULH&P's DCF analysis is inappropriate because investors would be doubly compensated.

ULH&P and the AG both proposed a 3.5 percent flotation cost adjustment in this case. ULH&P's adjustment was on the belief that a flotation cost adjustment is proper regardless of whether or not a new stock issuance is planned.[98] The AG's adjustment was on the belief of an expected need for external financing to fund ULH&P's construction budget over the next five years.[99]

ULH&P provided an analysis of flotation cost for its parent CG&E during the past 10 years and arrived at an average actual flotation cost of 3.57 percent.[100] Excluded from this average was a "bought" deal in which issuance cost were substantially lower than usual according to ULH&P. Stock may be issued through numerous means and the Commission does not believe the costs associated with a private placement should be excluded from an evaluation of actual cost. The AG merely accepted ULH&P's figure.[101]

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97 Id., page 36.

98 Mosley Direct Testimony, page 11.

99 Weaver Direct Testimony, page 35.

100 ULH&P Exhibit JRM, page 5, filed November 18, 1991.

101 Weaver Direct Testimony, page 36.

ULH&P would have the Commission believe that all of its equity capital is the result of public stock offerings; however, equity investment made by CG&E could come from other sources, such as CG&E's internally generated funds or debt.[102] The flotation cost adjustment should not be allowed because it overstates ULH&P's required return on equity. The percentage is not truly reflective of cost to CG&E and applicability to ULH&P.

The Commission has traditionally used the DCF model to assess comparable companies rather than companies of comparable risk. The two are not altogether in conflict. There is merit to comparable risk, in fact this would often be one of the selection criteria for comparable companies. ULH&P and the AG both used a mixture of historical and forecasted rates to determine growth. There is no compelling evidence that investors expect historical trends to continue into the future. A premium is not essential to account for ULH&P's greater risk relative to its proxy. If the proxy is truly of comparable risk then no additional adjustment is necessary.

The Commission has for a number of years considered the risk premium method for determining cost of common equity to be unreliable because it is subject to significant fluctuations due to the volatility of the bond and stock markets. The AG also disagreed with ULH&P's use of the risk premium method.

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102 Id., page 35-36.

Considering all factors, the risk premium study should not be utilized in this case.

The Commission affirms its traditional use of the DCF model to estimate ROE and continues to believe that the DCF method cannot be applied in a pure mechanistic manner. Considering all of the evidence, including current economic conditions, we find that the cost of common equity is within a range of 11.0 percent to 12.0 percent. Within this range, an ROE of 11.5 percent will best allow ULH&P to attract capital at a reasonable cost, maintain its financial integrity to ensure continued service and to provide for the necessary expansion to meet future requirements, and also result in the lowest possible cost to ratepayers.

Rate of Return Summary

Applying the rates of 9.375 percent for long-term debt, 5.935 percent for short-term debt, and 11.5 percent for common equity to the capital structure produces an overall cost of capital of 10.11 percent, which we find to be fair, just, and reasonable. This cost of capital produces a rate of return on ULH&P's jurisdictional net original cost rate base of 9.80 percent which the Commission finds is fair, just, and reasonable.

REVENUE REQUIREMENTS

ULH&P needs additional annual operating income of $13,375,933 to produce a rate of return of 11.5 percent on common equity based on the adjusted historical test year. After the provision for state and federal taxes, PSC Assessment, and increased uncollectibles, there is an overall revenue deficiency of $22,334,942 which is the amount of additional revenue granted.

The net operating income necessary to allow ULH&P the opportunity to pay its operating expenses and fixed costs and have a reasonable amount for equity growth is $8,997,310. The required operating income and the increase in revenue allowed herein is as follows.

Net Operating Income Found Reasonable	$ 8,997,310
Adjusted Net Operating Income	(4,378,623)
Net Operating Income Deficiency	13,375,933
Gross Up Revenue Factor for Taxes, PSC Assessment, and Uncollectibles	1.66979
Additional Revenue Required	22,334,942

The additional revenue granted will provide a rate of return on the jurisdictional net original cost rate base of 9.80 percent and an overall return on total electric capitalization of 10.11 percent.

The rates and charges in Appendix A are designed to produce gross operating revenues, based on the adjusted test year, of $171,158,963.

PRICING AND TARIFF ISSUES

Cost-of-Service Studies

ULH&P and the AG both filed fully-allocated embedded cost-of-service studies for the year ending July 31, 1991. The assumptions and methodologies used by the two parties in developing the studies differ significantly, which explains the disparity that exists in the results of the studies.

The results of ULH&P's study indicate a significant variation in the contribution each class makes to the overall electric

system rate of return of 10.28. The class rates of return as determined by ULH&P are as follows: Residential, 5.14; Distribution, 27.12; Transmission, 4.07; Lighting, 28.69; and Other, 41.27.[103] This study indicates that the Residential and Transmission classes are contributing less toward the system rate of return than the other classes.

The AG's study showed the following class contributions to the overall electric system rate of return of 10.28: Residential, 14.91; Distribution, 9.49; Transmission, -59.19; Lighting, 11.59; and Other, 38.67.[104] This study indicates that the Distribution and Transmission classes are contributing less than the other classes toward the system rate of return.

ULH&P used a 12 coincident peak ("12-CP") demand allocation factor to allocate demand-related production and transmission costs to customer classes. Under this method, all such costs are allocated to customer classes on the basis of each class's contribution to the 12 monthly maximum system peaks. The 12-CP method, like other peak demand methods, is predicated on the assumption that a utility's investment in production plant is determined only by system peak demands.

ULH&P divides distribution costs into demand-related and customer-related components by using percentages supposedly

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[103] Van Curen Testimony, Exhibit PVC-ECOS, Schedule 1.

[104] Kinloch Testimony, Exhibit DHK-6, Page 1 of 19, Schedule 1.

determined in a minimum-intercept study performed in a previous case.[105] Using this criteria, ULH&P classifies 80 percent of distribution costs as demand-related and 20 percent as customer-related. Demand-related distribution costs are then allocated on the basis of a class's non-coincident peak demand. Customer-related distribution costs are allocated based on the number of distribution customers. Various other plant and expense allocation factors were also used by ULH&P.

The AG allocated demand-related production and transmission costs using a variation of the average and excess method. This method recognizes that a portion of a utility's production plant is determined by durational or energy loads. The average and excess method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak demands.[106] The AG describes his allocation methodology as follows: "The amount of capacity associated with the average load is based on each class's contribution to the average load. The excess capacity above the average is allocated using ULH&P's 12 CP method."[107]

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105 ULH&P's Response to Item 73 of the Commission's Order dated December 17, 1991.

106 National Association of Regulatory Utility Commissioners' ("NARUC") "Electric Utility Cost Allocation Manual," revised in January 1992, page 49.

107 Kinloch Testimony, page 36.

In addition to the demand allocator, the AG modified three other allocators used by ULH&P. The first is ULH&P's allocator K414, which is used to allocate certain costs related to distribution plant. This allocator classifies 80 percent of distribution costs as demand-related and 20 percent as customer-related. The AG argued that distribution plant should be separated into primary and secondary components. ULH&P does not separate distribution plant in this manner. The AG maintains that the primary component should be allocated on the basis of system non-coincident peak, while the secondary component should be allocated on the basis of the summation of individual non-coincident peaks.[108] Using ULH&P's assumption that 80 percent of distribution costs are demand-related and 20 percent are customer-related, the AG allocated over three-fourths of the demand portion--the primary component--using his allocator A202 (average and excess at distribution). The remaining portion of demand-related distribution costs--the secondary component--are allocated using ULH&P's allocator K202 (total non-coincident KW).

Secondly, the AG modified ULH&P's administrative and general allocation factor K410. The AG claimed that a more accurate method of allocating these costs is based on the portion of other operating and maintenance expenses assigned to each class, less purchased power and fuel costs. Lastly, the AG modified ULH&P's allocator K206 (PSCKY net distribution plant less account 106) to

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108 Id., page 38.

reflect his allocation of distribution costs. The AG also modified several allocators assigned to individual plant and expense items.

The Commission finds numerous deficiencies in both cost-of-service studies presented in this case. In ULH&P's study, a 12-CP demand allocator is developed for the test year ending July 1991 by using load research and other data from time periods other than the test year. In fact, the most recent data used in developing the 12-CP demand allocation factor is from the year ending October 1990. Some of the data used in the development of this allocation factor is as much as 11 years old. In total, data from at least four different time periods, ranging from 1980 to 1990, are used in this calculation. The NARUC cost allocation manual states that the minimum data requirement for the 12-CP demand allocation method is reliable monthly load research data for each class of customers and for the total system.[109] As numerous variables, such as weather, economic factors, and appliance stocks and efficiencies fluctuate over time periods, it is very unlikely that data from so many different time periods is either reliable or representative of current conditions and, therefore, should not be used to calculate an allocation factor in this case.

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[109] NARUC's "Electric Utility Cost Allocation Manual," revised in January 1992, page 46.

ULH&P did not perform a minimum-intercept or zero-intercept study in this case in order to divide distribution costs into demand-related and customer-related components. When asked how it determined the percentages of demand-related and customer-related distribution plant, ULH&P claimed to have performed a minimum-intercept study.[110] However, ULH&P could not determine when such a study was performed.[111] The Commission has determined that ULH&P did not perform a minimum-intercept or zero-intercept study in Case No. 90-041[112] and cannot determine whether ULH&P performed such a study in Case No. 9299[113] (the rate case preceding Case No. 90-041). Even if such a study was performed in Case No. 9299, it is doubtful that the results of the study, which depend on current and detailed distribution plant and cost data, would still be reliable, as that case was decided in October 1985.

The AG criticizes ULH&P's failure to divide distribution plant into primary and secondary components and to allocate each component using separate allocation factors. ULH&P claims that it

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110 ULH&P's Response to Item 73 of the Commission's Order dated December 17, 1991.

111 T.E., Volume II, page 141.

112 Case No. 90-041, An Adjustment of Gas and Electric Rates of the Union Light, Heat and Power Company.

113 Case No. 9299, An Adjustment of Electric Rates of The Union Light, Heat and Power Company.

does not maintain its accounting records in that manner as such a separation of distribution costs into primary and secondary components is not required by the USoA established by the Federal Energy Regulatory Commission.[114] NARUC states that "in order to recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications."[115] The Commission believes that, given the distinct voltage characteristics of distribution facilities, a separation of certain distribution costs into primary and secondary components is appropriate and necessary. ULH&P should begin separating distribution facilities into primary and secondary components for use it its next cost-of-service study.

The AG's cost-of-service study presents its demand allocation methodology as an "average and excess" method. However, as pointed out by ULH&P, the AG's calculation of this allocation factor differs significantly from that prescribed by the NARUC in its "Electric Utility Cost Allocation Manual."[116] The AG admitted

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[114] T.E., Vol. II, page 140.

[115] NARUC's "Electric Utility Cost Allocation Manual," revised January 1992, page 89.

[116] ULH&P's Brief, pages 26-27.

that the NARUC method did not achieve the results he wanted, so he modified it according to his own assumptions and judgment.[117] The modifications made by the AG to the average and excess methodology are inconsistent with the methodology prescribed by NARUC and are inappropriate for the allocation of production and other demand-related costs.

Distribution costs should be separated into primary and secondary components. NARUC considers such a division of distribution costs necessary and other utilities presenting cost-of-service studies before this Commission have made such a bifurcation. However, partly because of unavailable data from ULH&P, the AG divides these costs by using percentages found to be appropriate by Louisville Gas and Electric Company ("LG&E") and Kentucky Power Company ("KPC") in recent rate cases.[118] It is unreasonable to assume that the primary and secondary split in LG&E's and KPC's distribution plant is at all similar to that of ULH&P. The make-up of each utility's distribution plant is unique and cannot be used as a proxy for another utility.

The AG used and modified several of the allocation factors developed by ULH&P in its cost-of-service study. Some of these factors have been improperly calculated by ULH&P, <u>infra</u>. The AG's use of these improper factors renders the AG's calculations

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[117] AG's Response to Item 10 of ULH&P's Information Request dated February 10, 1992.

[118] T.E., Vol. V, March 23, 1992, page 98.

inappropriate. The most obvious cases are the AG's use of ULH&P's 12-CP demand allocation factor (K200) in the calculation of the AG's average and excess allocator and the use of ULH&P's division of distribution plant as 80 percent demand-related and 20 percent customer-related in the AG's calculation of primary and secondary distribution plant components.

The Commission finds that both cost-of-service studies presented in this case are inappropriate, unreliable and should be rejected.

The Commission is aware of the on-going debate regarding the appropriate methodologies to be used to allocate demand-related plant and expense items. In cost-of-service studies presented in this case, ULH&P advocated the use of a 12-CP demand method while the AG used a modified "average and excess" method. The 12-CP demand method belongs to the family of peak demand methods, while the average and excess method is a type of energy weighting method.

The most fundamental difference between these two methodologies is the way in which a utility's investment in production plant is viewed. Proponents of a 12-CP or other peak demand method claim that a utility's production plant is built only for the purpose of serving peak load, whether individual monthly peaks or the annual system peak. Thus, all demand-related production costs must be allocated to customer classes on the basis of each class's contribution to the system peak. Under this scenario, if a customer class, such as street lighting, does not use the system at the time of system peak, no production costs

would be allocated to it. Proponents of an average and excess method or some other energy weighting method claim that a utility's production plant is built not only to serve peak demand but also to serve off-peak base load. For this reason, all classes should bear some of the costs of producing electricity regardless of a class's use of the system at the time of system peak. There are also time-differentiated methodologies such as the Base-Intermediate-Peak ("BIP") method that allocate production plant costs to off-peak baseload hours, intermediate "shoulder peak" hours, and peak hours. ULH&P and other interested parties may want to refer to the description of these methodologies as set forth in the NARUC's "Electric Utility Cost Allocation Manual" which was revised in January 1992.

Over the years, the Commission has accepted cost-of-service studies that used demand allocation methodologies from each of these different categories. There are convincing arguments that can be made for any of these methods. For this reason, the Commission recommends that, in future rate cases, ULH&P file multiple cost-of-service studies that use, among other things, demand allocation methods from each of the peak demand, energy weighting, and time-differentiated families of production plant allocation methodologies. To the extent possible, intervenors should also present multiple cost-of-service studies using various methodologies. By having multiple cost-of-service studies presented in rate cases, the Commission is convinced that a more reasonable and informed decision can be made regarding the appropriate allocation of revenue to customer classes.

Revenue Allocation

Based on the results of its cost-of-service study, ULH&P proposed to allocate its requested increase as follows: 24.7 percent to the residential class; 16.7 to 18.9 percent to the commercial and industrial classes; and approximately 10.3 percent to its lighting classes. The AG, based on his cost-of-service study and assuming the full increase was granted, proposed 19 to 20 percent increases for residential and commercial customers, an approximate 30 percent increase for industrial customers, and an approximate 10 percent increases for ULH&P's lighting class customers.

Inasmuch as the Commission has rejected both of the proposed cost-of-service studies neither study will be used to allocate the revenue increase. The increase will be allocated to ULH&P's customer classes in the same proportions each class currently contributes to ULH&P's total electric revenues. This approach, which is traditionally utilized when no cost-of-service study has been presented, maintains the existing allocation between classes and results in each class receiving approximately the same overall percentage increase. In this instance, all classes will receive increases of approximately 15 percent.

Residential Rate Design

The AG proposed that ULH&P's residential rates, which consist of a flat summer rate and a two-step declining block winter rate, be restructured to include inverted (inclining block) rates both in summer and winter. While the first step of the existing winter rate encompasses 0 to 1,000 KWH, the AG would have the first step

of the two-step rate cover only 0 to 700 KWH. Based on his analysis of ULH&P's monthly power costs, the AG opined that, under ULH&P's existing rate structure, temperature-sensitive power is being underpriced and customers are being encouraged to overuse or waste energy, resulting in higher costs for all customers.

ULH&P opposed the AG's proposal arguing that reducing the first block to 700 KWH would be cutting into non-temperature sensitive loads and would be punitive to its all-electric customers. ULH&P contends that its existing winter rate design, with the break point at 1,000 KWH, properly recognizes its all-electric customers usage patterns and should not be changed absent end-use data which would support such a change. ULH&P also contested the AG's determination of baseload costs and temperature-sensitive load costs, two components in the AG's calculation of inverted rates.

The AG's proposal has some merit in light of ULH&P's summer load characteristics. ULH&P's cooling load is the primary force driving its predominant summer peak while it experiences its heating load during its off-peak (winter) season. The Commission recognizes that increased off-peak demands can produce many of the same benefits as reduced on-peak demands, such as improved system load factor and lower unit costs. Given these circumstances, the Commission finds that ULH&P's residential rates should be modified to include an inverted block summer rate but should retain a declining block winter season rate. The Commission shares ULH&P's concerns about reducing the break point in its residential rate schedule without the benefit of end-use data and, therefore, will

maintain the existing break point of 1,000 KWH. We are, however, interested in pursuing this matter further in ULH&P's next general rate case. ULH&P shall address the appropriate structure of its residential rates in that case. In keeping with our stated goals of gradualism and rate continuity, the Commission will take a moderate approach to implementing an inverted summer rate by increasing the second rate block by approximately one-and-one-half times the increase to the first block.

Bad Check Charges

ULH&P proposed to increase from $8 to $15 its charge for receiving and processing bad checks to serve as a deterrent to customers that might issue such checks. ULH&P indicated the proposed charge was comparable to the charges assessed by local businesses and financial institutions.

The AG opposed the increase, claiming that publicizing the existing charge would serve as a more effective deterrent than increasing the charge by 87 percent. The AG argued that the proposed charge is not cost based and that any increase should be limited to the level of the overall increase granted in this case.

ULH&P has not provided sufficient cost support to justify the requested $7 increase in the bad check charge. Customers must be aware of the charge before it can become an effective deterrent. In the absence of cost support, the charge should remain at $8.

Late Payment Charges

The AG proposed that the Commission direct ULH&P to change the way in which it credits partial payments from customers carrying a past-due balance from a previous month. The proposal

would require that, when a customer pays enough to cover the current month's bill plus at least $5 toward the past-due balance, the payment should first be credited to the current month's bill rather than to the customer's oldest balance first. The AG argued that such a change was needed to eliminate the practice of a customer paying late payment charges month after month when the customer wasn't late in paying his bill but was merely unable to pay the full amount of his current bill and his past-due balance.

ULH&P opposed the proposal arguing that the AG was wrong in claiming that a customer could pay a late payment charge on the same balance month after month under the existing late payment provision. ULH&P contends that a late payment charge is applied to a past due balance only once under its current procedure.

The Commission is persuaded to adopt the AG's proposal. The proposal will apply only when the customer pays his current month's bill in full and makes a contribution of at least $5 toward his past due balance. While leaving intact ULH&P's late payment provision, the proposal will remove the customer's disincentive for making a timely partial payment by eliminating the recurrence of a late payment charge.

Rate and Tariff Changes

ULH&P proposed few structural changes to its existing rates or tariff schedules. ULH&P did propose to modify its electric space heating tariff, Rate EH, an optional rate for non-residential customers having a demand of less than 500 KW. The modification would remove the rate's limitation to customers receiving similar service prior to June 25, 1981. ULH&P proposed

to add a second step to Rate GS-FL for general service fixed loads of less than 540 hours use per month. ULH&P also proposed to add a rate step for traffic lighting service to cover situations where company personnel provide limited maintenance for traffic signal equipment but energy is supplied from a separately-metered source. On its outdoor lighting schedule, Rate OL, ULH&P proposed to delete and add various lighting units and to give customers the option of making a one-time up-front contribution for a decorative unit in order to reduce the regular monthly charge to that of a standard unit. On its non-standard private lighting schedule, Rate NSP, ULH&P proposed to limit the availability of some units to those customers served at the time this application was filed.

The changes described above and other text modifications proposed by ULH&P were not contested by any party. The Commission has reviewed these changes and finds they should be approved with the exception that the limitations on Rate NSP shall be prospective from the effective date of this Order. The new rate steps and new lighting units are set out in Appendix A. The text changes are not included in the Appendix.

MANAGEMENT AUDIT

General

In its final Order in Case No. 90-041, the Commission expressed several concerns with ULH&P's response to the 1989 management audit performed by Schumaker & Company. The Commission clearly stated that it found it appropriate to review ULH&P's audit-related activities in formal rate case proceedings. In addition, the Commission stated that it considered the audit

report "to constitute substantial evidence regarding potential cost savings measures available"[119] to ULH&P and also clearly indicated that adjustments related to the management audit recommendations may be considered in future rate proceedings.

In this proceeding, ULH&P initially provided a schedule of test-year costs and benefits attributable to the implementation of management audit recommendations.[120] That schedule reflected "Per Auditor" and "Per Company" costs and benefits for 53 recommendations. In response to a request for specific detailed information relating to the schedule, ULH&P indicated that a schedule with the information and level of detail requested did not exist.[121] ULH&P subsequently disclosed that there were several errors in that schedule, and that it does not have the accounting mechanisms in place to specifically identify allocated individual recommendation costs in the test year.[122] ULH&P has also stated that creating and maintaining a special detailed reporting system to track the success of implemented management audit recommendations would be prohibitively expensive and a waste of manpower and resources.[123]

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119 Id., page 76.

120 Response to the Commission's Order dated November 14, 1991, Item 49.

121 Response to the Commission's Order dated December 17, 1991, Item 63.

122 Response to the Commission's Order dated January 17, 1992, Item 47.

123 Id., Item 48.

However, in a December 1991 summary report of ULH&P's implementation progress prepared by the Commission's Management Audit Branch, which was reviewed by ULH&P prior to publication, 11 recommendations with a net savings or cost avoidance of $987,400 to $995,400 were identified as being implemented. Four recommendations with an identified savings of $803,000 were directly related to the Electric Operations Department and four recommendations with an identified savings of $52,900 to $60,900 were in the Customer Service or Administrative services area and were indirectly related to Electric Operations.[124] The amounts included in the summary report were derived from ULH&P's progress reports submitted to the Management Audit Branch as part of the management audit follow-up process.

If such information can be provided in regular periodic reports to the Commission's Management Audit Branch but cannot be addressed with any certainty in a rate proceeding, the Commission must not only question the accuracy of the savings identified by ULH&P in its periodic progress reports but also the intentions of ULH&P to follow through on its actions to achieve these savings.

While recognizing that savings and efficiency enhancements are not always represented by actual reductions in current dollars

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[124] Summary Report: The Union Light, Heat And Power Company's Progress In Implementing The Management Audit Recommendations, dated December 1991.

but may also represent future avoided costs, the Commission believes that successful implementation of reasonable and appropriate audit recommendations provides benefits to both ULH&P's customers and shareholders. The customers benefit to the extent that increased productivity and efficiency allow ULH&P to meet its service obligations more economically. This, in turn, benefits the owners by enhancing ULH&P's ability to earn its authorized rate of return.

As audit recommendations are implemented, the Commission fully expects ULH&P to provide appropriate cost/benefit analyses supporting its efforts in the periodic progress reports and, when requested, in rate proceedings. To ensure that customers, as well as owners, receive the benefits of implemented recommendations, the Commission, in future rate proceedings, will require ULH&P to provide appropriate detailed information of costs, benefits, and/or costs avoided as a result of its related efforts regardless of the accounting or reporting mechanisms now in place. This information should correspond to the information periodically provided to the Commission's Management Audit Branch, or a fully detailed explanation of differences should be provided. If costs and benefits are not adequately addressed in future rate proceedings, the Commission will make appropriate adjustments.

In requiring this information, the Commission is not requesting ULH&P to develop additional reporting procedures. We are, however, requiring ULH&P to comply with the requirements of

the USoA which requires utilities to keep their books of account and all supporting documentation in a manner as to be able to readily furnish full information as to any item included in any account.[125]

Individual Recommendations

ULH&P indicated that it understood that three recommendations were subject to discussion and determination by the Commission.[126] Since ULH&P further addresses these three "agree to disagree" recommendations and requests that the Commission determine how they are to be resolved,[127] the Commission will address each recommendation.

With regard to the recommendation to request additional feedback from the external auditors, the Commission does not fully agree with ULH&P's and the Board of Directors' Audit Committee's position regarding formal written communication. However, considering the decision of management and that other appropriate procedures are in place, the Commission will require no further action relative to this recommendation. Should the situation change or problems arise, however, the Commission fully expects appropriate changes to be instituted.

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125 Uniform System of Accounts, Publication Number FERC-0114, General Instructions, No. 2(A).

126 T.E., Vol. IV, March 20, 1992, page 80.

127 Brief of ULH&P, pages 33 through 36.

With regard to the recommendation to assign responsibility for salary administration, at all levels of the organization, to the Human Resource Department's Compensation and Benefits Division, the Commission finds that the decision to leave administration of management employees' compensation with the Assistant Secretary rather than transfer responsibility to the seemingly more appropriate Human Resources group to be inconsistent with the Commission's understanding of the typical duties and responsibilites of a human resource function. There is evidence regarding the reorganization of the human resource function and changing corporate culture.[128] No further action will be required at this time. However, with the changes taking place in the human resources area, the Commission would expect ULH&P to reconsider this recommendation should administration by the Human Resource function become appropriate.

With regard to the recommendation that ULH&P's Legal Department develop time sheets to record actual charges to ULH&P in enough detail to identify specific projects and services, the Commission will require that this recommendation be reconsidered and included in any determination made by ULH&P regarding the supervisory, administrative, and professional cost-allocation and time study issues addressed earlier in this Order.

To the extent that other recommendations remain ongoing or not completely implemented, the Commission fully expects ULH&P and

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128 T.E., Volume III, March 19, 1992, pages 81 through 84, 143 through 148 and Volume IV, March 20, 1992, page 69.

CG&E (to the extent that such recommendations impact ULH&P) to make a good faith effort to satisfactorily report on implementation or provide specific detailed analyses to show why implementation is not reasonable.

With respect to recommendations that are ULH&P specific or are indirectly related to ULH&P, that are being studied as part of ULH&P's integrated operations, the Commission strongly believes that specific consideration should be given to the needs of the ULH&P service area and to its customers. As the management auditors stated, ULH&P, as an integral part of CG&E, should be in a position to benefit from a level of sophistication of management and technology that it would not otherwise be able to justify.[129] However, the evidence presented in this proceeding relative to recent increases in staffing levels, the failure of ULH&P to perform the referenced analysis of staffing levels, the inability or unwillingness to adequately address cost allocation issues, and the inability to address the specific costs and benefits of the management audit, raises significant questions as to whether Kentucky customers are indeed benefiting from this relationship.

SUMMARY

After consideration of all matters of record, the evidence, and being otherwise sufficiently advised, the Commission finds that:

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129 Management And Operations Review of The Union Light, Heat And Power Company, August 1989, page 29.

1. The rates in Appendix A, attached hereto and incorporated herein, are the fair, just, and reasonable rates to be charged subject to refund by ULH&P for service rendered on and after the date of this Order.

2. The rates proposed by ULH&P would produce revenue in excess of that found reasonable herein and should be denied.

3. The rate of return granted herein is fair, just, and reasonable, and will provide for the financial obligations of ULH&P with a reasonable amount remaining for equity growth.

4. The tariff changes proposed by ULH&P, as modified herein, are reasonable and should be approved.

IT IS THEREFORE ORDERED that:

1. The rates in Appendix A be and they hereby are approved subject to refund for service rendered by ULH&P on and after the date of this Order.

2. ULH&P shall maintain its records in such manner as will enable ULH&P, any of its customers, or the Commission to determine the amounts to be refunded and to whom due in the event a refund is ordered.

3. ULH&P shall file a notice with the Commission, with a copy to all parties of record, within 5 days of any change in the current FERC filed rate for purchased power.

4. The rates proposed by ULH&P be and they hereby are denied.

5. The tariff changes authorized herein and the tariffs set forth in Appendix A be and they hereby are approved.

6. Within 30 days from the date of this Order, ULH&P shall file with the Commission revised tariff sheets setting out the rates and tariff provisions approved herein.

Done at Frankfort, Kentucky, this 5th day of May, 1992.

PUBLIC SERVICE COMMISSION

Chairman

Commissioner

DISSENTING OPINION OF VICE CHAIRMAN THOMAS M. DORMAN

I respectfully dissent from the decision to allow ULH&P to increase its retail rates by approximately $25 million to recover increased purchase power costs due solely to the commercialization of Zimmer. CG&E's cost to convert the substantially completed nuclear facility to a coal facility should be borne by CG&E's shareholders and not by Kentucky ratepayers. There is no valid reason to justify the cost of Zimmer being at least 50 percent greater than the current cost for comparable generation.

While the rate increase authorized by the majority is subject to refund pending a full and comprehensive review of the Zimmer cost by the FERC, I strongly believe that ratepayers should not be burdened with excessive and uncertain Zimmer costs during the interim. This Commission has intervened at the FERC and will soon

be sponsoring expert testimony on the unreasonableness of Zimmer's cost. As long as the Kentucky Public Service Commission is an intervenor and until the FERC has considered all the evidence and approved a final rate for purchased power, this Commission should object to any scheme which seeks to recover unreasonable Zimmer costs from Kentucky ratepayers.

Thomas M. Dorman
Vice Chairman

ATTEST:

Executive Director, Acting

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 91-370 DATED MAY 5, 1992

The following rates and charges are prescribed for the customers in the area served by The Union Light, Heat and Power Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

ELECTRIC SERVICE RATES

RATE RS
RESIDENTIAL SERVICE

Customer Charge	$3.89 Per Month
Energy Charge	
Summer Rate	
First 1,000 Kilowatt-Hours	6.806¢ Per KWH
Additional Kilowatt-Hours	7.265¢ Per KWH
Winter Rate	
First 1,000 Kilowatt-Hours	6.806¢ Per KWH
Additional Kilowatt-Hours	5.359¢ Per KWH

RATE DS
SERVICE AT SECONDARY DISTRIBUTION VOLTAGE

NET MONTHLY BILL

Computed in accordance with the following charges provided, however, that the maximum monthly rate, excluding the customer charge and the electric fuel component charges, shall not exceed 19.851 cents per kilowatt-hour.

Customer Charge	
Single Phase Service	$5.00 Per Month
Three Phase Service	$10.00 Per Month
Demand Charge:	
First 15 Kilowatts	$0.00 Per KW
Additional Kilowatts	$6.84 Per KW

Energy Charge	
First 6,000 KWH	7.192¢ Per KWH
Next 300 KWH/KW	4.386¢ Per KWH
Additional KWH	3.631¢ Per KWH

For customers receiving service under the provisions of former Rate C, Optional Rate for Churches, as of June 25, 1981, the maximum monthly rate per kilowatt-hour shall not exceed 11.775 cents per kilowatt-hour plus the applicable fuel adjustment charge.

RATE DT
TIME-OF-DAY RATE FOR SERVICE AT DISTRIBUTION VOLTAGE

Customer Charge	
Single Phase Service	$5.00 Per Month
Three Phase Service	$10.00 Per Month
Primary Voltage Service	$100.00 Per Month
Demand Charge	
Summer	
On Peak KW	$10.20 Per KW
Off Peak KW	$1.00 Per KW
Winter	
On Peak KW	$8.42 Per KW
Off Peak KW	$1.00 Per KW
Energy Charge	
All KWH	3.656¢ Per KWH

RATE EH
OPTIONAL RATE FOR ELECTRIC SPACE HEATING

Winter Period	
Customer Charge	
Single Phase Service	$5.00 Per Month
Three Phase Service	$10.00 Per Month
Primary Voltage Service	$100.00 Per Month
Demand Charge	
All KW	$0.00 Per KW
Energy Charge	
All KWH	5.371¢ Per KWH

RATE SP
SEASONAL SPORTS SERVICE

Customer Charge	$5.00 Per Month
Energy Charge	8.993¢ Per KWH

RATE GS-FL
OPTIONAL UNMETERED GENERAL SERVICE RATE FOR SMALL FIXED LOADS

For Loads Based on a Range of 540 to 720 Hours Use Per Month of the Rated Capacity of the Connected Equipment	7.079¢ Per KWH
For Loads of Less Than 540 Hours Use Per Month of the Rated Capacity of the Connected Equipment	8.160¢ Per KWH

RATE DP
SERVICE AT PRIMARY DISTRIBUTION VOLTAGE

Customer Charge	
Primary Voltage Service (12.5 or 34.5 KV)	$100.00 Per Month
Demand Charge:	
All Kilowatts	$6.35 Per KW
Energy Charge	
First 300 KWH/KW	4.434¢ Per KWH
Additional KWH	3.650¢ Per KWH

RATE TT
TIME-OF-DAY RATE FOR SERVICE AT TRANSMISSION VOLTAGE

Customer Charge	$500.00 Per Month
Demand Charge	
Summer	
On Peak KW	$6.92 Per KW
Off Peak KW	$1.00 Per KW
Winter	
On Peak KW	$5.65 Per KW
Off Peak KW	$1.00 Per KW
Energy Charge	
All KWH	3.606¢ Per KWH

RATE SL
STREET LIGHTING SERVICE

OVERHEAD DISTRIBUTION AREA

	Rate/Unit
Standard Fixtures	
Mercury Vapor	
7,000 Lumen	$4.99
7,000 Lumen (Open Refractor)	$3.86
10,000 Lumen	$5.38
21,000 Lumen	$6.76
Sodium Vapor	
9,500 Lumen	$6.23
9,500 Lumen (Open Refractor)	$4.46
16,000 Lumen	$6.46
22,000 Lumen	$8.35
50,000 Lumen	$10.02
Decorative Fixtures	
Sodium Vapor	
9,500 Lumen (Rectilinear)	$7.95
22,000 Lumen (Rectilinear)	$9.08
50,000 Lumen (Rectilinear)	$10.97
50,000 Lumen (Setback)	$18.00

Spans of Secondary Wiring

For each increment of 50 feet of secondary wiring beyond the first 150 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.47.

UNDERGROUND DISTRIBUTION AREA

	Rate/Unit
Standard Fixtures	
Mercury Vapor	
7,000 Lumen	$4.99
7,000 Lumen (Open Refractor)	$3.86
10,000 Lumen	$5.38
21,000 Lumen	$6.76
Sodium Vapor	
9,500 Lumen	$6.23
9,500 Lumen (Open Refractor)	$4.46
16,000 Lumen	$6.46
22,000 Lumen	$8.35
50,000 Lumen	$10.02
Decorative Fixtures	
Mercury Vapor	
7,000 Lumen (Town & Country)	$5.23
7,000 Lumen (Holophane)	$6.93
7,000 Lumen (Gas Replica)	$17.81
7,000 Lumen (Aspen)	$10.73

Sodium Vapor	
9,500 Lumen (Town & Country)	$8.98
9,500 Lumen (Holophane)	$9.53
9,500 Lumen (Rectilinear)	$7.95
9,500 Lumen (Gas Replica)	$19.10
9,500 Lumen (Aspen)	$11.40
22,000 Lumen (Rectilinear)	$9.08
50,000 Lumen (Rectilinear)	$10.97
50,000 Lumen (Set Back)	$18.00

POLE CHARGES

Pole Description	Rate/Pole
Wood	
17 Foot (Laminated)	$3.96
30 Foot	$3.90
35 Foot	$3.96
40 Foot	$4.74
Aluminum	
12 Foot (Decorative)	$10.41
28 Foot	$6.25
28 Foot (Heavy Duty)	$6.30
30 Foot (Anchor Base)	$12.49
Fiberglass	
17 Foot	$3.96
12 Foot (Decorative)	$11.66
30 Foot (Bronze)	$7.60
35 Foot (Bronze)	$7.81
Steel	
27 Foot (11 Gauge)	$10.25
27 Foot (3 Gauge)	$15.46

Spans of Secondary Wiring

For each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.67.

RATE TL
TRAFFIC LIGHTING SERVICE

NET MONTHLY BILL

Where the Company supplies energy only, all kilowatt-hours shall be billed at 3.22 cents per kilowatt-hour.

Where the Company supplies energy from a separately metered source and the Company has agreed to provide limited maintenance for traffic signal equipment, all Kilowatt-Hours shall be billed at 1.88 cents per Kilowatt-Hour.

Where the Company supplies energy and has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 5.10 cents per kilowatt-hour.

RATE OL
OUTDOOR LIGHTING SERVICE

Private Outdoor Lighting Units

	Rate/Unit
Standard Fixtures	
Mercury Vapor	
7,000 Lumen (Open Refractor)	$6.27
7,000 Lumen	$8.43
10,000 Lumen	$9.49
21,000 Lumen	$11.56
Sodium Vapor	
9,500 Lumen (Open Refractor)	$5.97
9,500 Lumen	$8.05
16,000 Lumen	$8.40
22,000 Lumen	$9.45
50,000 Lumen	$9.51
Decorative Fixtures	
Mercury Vapor	
7,000 Lumen (Town & Country)	$10.42
7,000 Lumen (Holophane)	$13.86
7,000 Lumen (Gas Replica)	$35.63
7,000 Lumen (Aspen)	$21.47
Sodium Vapor	
9,500 Lumen (Town & Country)	$17.92
9,500 Lumen (Holophane)	$19.07
9,500 Lumen (Rectilinear)	$15.89
9,500 Lumen (Gas Replica)	$38.24
9,500 Lumen (Aspen)	$22.82
22,000 Lumen (Rectilinear)	$18.13
50,000 Lumen (Rectilinear)	$21.93
50,000 Lumen (Setback)	$35.90

Flood Lighting Units Served in Overhead Distribution Areas

	Rate/Unit
Mercury Vapor	
21,000 Lumen	$11.56
Sodium Vapor	
22,000 Lumen	$9.24
50,000 Lumen	$10.16

RATE NSU
STREET LIGHTING SERVICE
FOR NON-STANDARD UNITS

Company Owned

	Rate/Unit
Boulevard Units Served Underground	
2,500 Lumen Incandescent - Series	$7.14
2,500 Lumen Incandescent - Multiple	$4.99
Holophane Decorative Fixture on 17 foot fiberglass pole served underground with direct buried cable	
10,000 Lumen Mercury Vapor	$12.81

The cable span charge of $.67 per each increment of 25 feet of secondary wiring shall be added to the Rate/Unit charge for each increment of secondary wiring beyond the first 25 feet from the pole base.

Street Light Units Served Overhead Distribution	
2,500 Lumen Incandescent	$4.94
2,500 Lumen Mercury Vapor	$5.18
21,000 Lumen Mercury Vapor	$6.13

Customer Owned

	Rate/Unit
Steel Boulevard Units Served Underground with Limited Maintenance by Company	
2,500 Lumen Incandescent - Series	$3.76
2,500 Lumen Incandescent - Multiple	$4.78

RATE NSP
PRIVATE OUTDOOR LIGHTING FOR NON-STANDARD UNITS

	Rate/Unit
Private Outdoor Lighting Units:	
2,500 Lumen Mercury, Open Refractor	$6.12
2,500 Lumen Mercury, Enclosed Refractor	$8.66

Outdoor Lighting Units Served in Underground Residential Distribution Areas:	
7,000 Lumen Mercury, Mounted on a 17-foot Plastic Pole	$11.46
7,000 Lumen Mercury, Mounted on a 17-foot Wood Laminated Pole	$11.46
7,000 Lumen Mercury, Mounted on a 30-foot Wood Pole	$10.47
9,500 Lumen Sodium Vapor, TC 100 R	$9.13

Flood Lighting Units Served in Overhead Distribution Areas

52,000 Lumen Mercury (35-Foot Wood Pole)	$17.38
52,000 Lumen Mercury (50-Foot Wood Pole)	$20.60
50,000 Lumen Sodium Vapor	$14.20

RATE SC
STREET LIGHTING SERVICE - CUSTOMER OWNED

	Rate/Unit
Standard Fixtures	
Mercury Vapor	
7,000 Lumen	$2.38
10,000 Lumen	$2.82
21,000 Lumen	$3.58
Sodium Vapor	
9,500 Lumen	$3.62
16,000 Lumen	$3.86
22,000 Lumen	$3.92
50,000 Lumen	$4.14

	Rate/Unit
Decorative Fixtures	
Mercury Vapor	
7,000 Lumen (Holophane)	$3.29
7,000 Lumen (Town & Country)	$3.29
7,000 Lumen (Gas Light Replica)	$3.29
7,000 Lumen (Aspen)	$3.29
Sodium Vapor	
9,500 Lumen (Town & Country)	$3.64
9,500 Lumen (Rectilinear)	$3.64
9,500 Lumen (Aspen)	$3.75
9,500 Lumen (Holophane)	$3.75
9,500 Lumen (Gas Light Replica)	$3.75
22,000 Lumen (Rectilinear)	$3.92
50,000 Lumen (Rectilinear)	$4.14

	Rate/Pole
Pole Description	
Wood	
30 Foot	$3.90
35 Foot	$3.95
40 Foot	$4.73

The rate for energy used for this type of street lighting will be 3.169 cents per kilowatt-hour.

RATE SE
STREET LIGHTING SERVICE-OVERHEAD EQUIVALENT

	Rate/Unit
Decorative Fixtures	
Mercury Vapor	
7,000 Lumen (Town & Country)	$5.01
7,000 Lumen (Holophane)	$5.01
7,000 Lumen (Gas Replica)	$5.01
7,000 Lumen (Aspen)	$5.01
Sodium Vapor	
9,500 Lumen (Town & Country)	$6.25
9,500 Lumen (Holophane)	$6.25
9,500 Lumen (Rectilinear)	$6.25
9,500 Lumen (Gas Replica)	$6.25
9,500 Lumen (Aspen)	$6.25
22,000 Lumen (Rectilinear)	$8.35
50,000 Lumen (Rectilinear)	$10.02
50,000 Lumen (Setback)	$10.02

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 91-370 DATED MAY 5, 1992

The jurisdictional net original cost rate base of ULH&P's combined and electric operations at July 31, 1991 is as follows:

	Company	Electric
Total Utility Plant in Service	$269,104,101	$151,975,821
Add:		
Materials and Supplies -		
Distribution	70,214	70,214
Gas Enricher Liquids	2,331,564	0
Other	21,369	10,933
Total Materials and Supplies	2,423,147	81,147
Gas Stored Underground	793,152	0
Prepayments	609,058	144,418
Cash Working Capital Allowance	4,635,506	2,573,472
Subtotal	8,460,863	2,799,037
Deduct:		
Reserve for Accumulated Depreciation	80,606,579	49,078,228
Accumulated Deferred Income Taxes	20,619,989	13,726,430
Investment Tax Credits	239,091	96,010
Customer Advances for Construction	1,998,600	0
Subtotal	103,464,259	62,900,668
Jurisdictional Net Original Cost Rate Base	$174,100,705	$ 91,874,190

Ratio of Kentucky jurisdictional electric operations to total operations: 52.771 percent.

Notes:

1. Balances for Materials and Supplies and Prepayments were determined using 13-month average balances.

2. Prepayments do not include amounts for the PSC Assessment or auto license taxes.

3. Cash working capital allowance was determined by taking 1/8 of actual operation and maintenance expenses less energy charges for the test period.

4. Company amounts are on a jurisdictional basis.

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 91-370 DATED MAY 5, 1992

Commission's Adjustment To ULH&P's Overtime Labor Expense

Mathematic Average of Overtime Hours (Schedule C-11.1):

Year	Hours
1986	24,732
1987	50,244
1988	56,742
1989	85,863
1990	60,478
TY 7/91	62,535
Total	340,594
Average	56,766

Calculated Average Overtime Hourly Wage Rate, TY Actual:
(Schedule C-11.1)

Total Labor Overtime Dollars	$1,556,588
Total Overtime Hours	62,535
Average Overtime Rate per Hour	$24.8915

Calculation of Adjustment:

Computed Average Overtime Hours	56,766
Actual TY Overtime Hours	62,535
Proposed Reduction in Hours	(5,769)
Allocation to Electric	71.45%
Reduction Allocated to Electric	(4,122)
Average Overtime Rate per Hour	$24.8915
Electric Overtime Reduction	$(102,606)
O & M Labor Ratio (Sch. C-11.1)	72.43%
Electric O & M Overtime Reduction	$(74,318)
Jurisdictional Factor (Sch. C-11.1)	99.96%
Total Overtime Labor Reduction	$(74,287)

Note: The allocation to electric operations reflects the percentage of electric operating revenues to total operating revenues, as shown on Schedule A-3.9 of ULH&P's application.

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 91-370 DATED MAY 5, 1992

Commission's Adjustments For Employee-Related and Miscellaneous Expenses.

Account	Description	Amount
Employee-Related Expenses:		
5926-50	Americana Amusement Park - Company Picnic	$ 2,119
5926-50	Walk America / March of Dimes	228
5926-50	Children's Christmas Party	225
	Total Adjustments to Employee-Related Expenses	$ 2,572
Miscellaneous - Inappropriate for Rate-Making:		
Various	Burson-Marsteller - Commun. Act. Involvement	$ 3,142
5930-25	Color Brite Fabrics & Displays	401
5930-25	Frontier Restaurant - Dinner after Zimmer Tour	1,004
5930-50	Greater Cincinnati Convention - Bureau Dues	156
Various	Home Builders Association - Membership Dues	233
5930-30	King's Island - Employee Appreciation Day	18,111
5930-25	Martiny & Company - Speaker's Bureau Booklet	1,190
Various	Municipal Government League - Mtg. attend.	104
Various	Terrace Garden Inn - Lodging/Homebuilders Conv.	122
Various	General Physics Corp. - Review Prepared. Plan	3,938
Miscellaneous - Reclassified to Account No. 426.1:		
Various	Christmas Train Display	$ 12,258
5930-50	Cincinnati Historical Society - Dues	188
5930-30	Cincinnati Theatrical Assoc. - Sponsorship	3,968
Various	Commonwealth Hilton - Govt. Mtg./Banquet Chrg.	3,119
5930-50	Covington Business - Membership Dues	326
5930-24	Covington Business - Sponsor City Center Dinner	167
5930-24	Dan Beard Council - Leadership Luncheon	140
5930-25	Diorama Presentations - Sponsor Wilderness Adv.	4,960
5930-25	Downtown Council of Cincinnati - Walking Guide	1,190
5930-25	Greater Cincinnati Convention - Decorating	1,488
5930-24	Kenton Co. Boys/Girls Club - Outing	291
5930-24	Kincaid Regional Theatre - Sponsorship	620
5930-24	Leadership Kentucky - Share of Reception	310
5930-25	Mrs. Allison's Cookie Company - Train Display	501
5930-30	Museum Center Foundation - Theater Sponsorship	4,960
5930-24	N. Kentucky Chamber of Commerce - Dinner Mtg.	434
5930-24	N. Kentucky Chamber of Commerce - Golf Outing	279
5930-24	N. Kentucky Chamber of Commerce - Sponsorship	310
Various	N. Kentucky Chamber of Commerce - Annual Outing	339
5909-25	N. Kentucky Reading Co. - Sponsorship	744
5930-24	N. Kentucky University - Sponsorship	372
5930-30	Riverfront Coliseum - Sponsorship NBA Exhib.	496
5921-61	The University of Dayton - Scholarships	242
5921-61	Thomas More College - Scholarship	504
5930-25	Three & Associates, Inc. - Wilderness Brochure	2,425
	Total Adjustments to Miscellaneous Expenses	$ 69,032