COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

SEP 2 1 2005

PUBLIC SERVICE
COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE GAS)
RATES OF THE UNION LIGHT,)
HEAT AND POWER COMPANY)

CASE NO. 2005-00042

POST-HEARING BRIEF OF THE ATTORNEY GENERAL

GREGORY D. STUMBO
ATTORNEY GENERAL

Elizabeth E. Blackford
Assistant Attorney General
Office of Rate Intervention
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601-8204
(502) 696-5453

September 21, 2005

TABLE OF CONTENTS

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE GAS)
RATES OF THE UNION LIGHT,)
HEAT AND POWER COMPANY)

CASE NO. 2005-00042

POST-HEARING BRIEF OF THE ATTORNEY GENERAL

On February 15, 2005, the Union Light, Heat and Power Company ("Union" or "ULH&P") filed an application seeking an increase in its general gas rates of $14,021,698 and continuation of the Rider AMRP, with that Rider to become operational one year after the close of the end of the future test year utilized for this filing. The Attorney General ("AG") is the only intervenor. Following extensive discovery, the filing of testimony by the Attorney General, and Rebuttal Testimony by Union, a hearing was conducted beginning July 20, 2005, for the purpose of cross examining witnesses. In accord with the procedural schedule entered in this case, this brief follows.

GAS JURISDICTIONAL CAPITALIZATION BALANCE

Based on a reflection of the reduced Kentucky Income tax of 7% and a jurisdictional rate base allocation factor of 4.899%, the Attorney General recommends a gas jurisdictional capitalization balance of $162,296,080. This amount is $3,423,133 lower than Union's proposed gas jurisdictional capitalization balance.[1] It reflects the impact of the reduction of the Kentucky income tax from 8.25% to 7% and the use of a gas jurisdictional rate base allocation factor of 25.337%.

[1] Direct Testimony (DT) of Robert J. Henkes (Henkes), p. 12.

Gas Jurisdictional Rate Base

In accord with long Commission precedent, the Gas Jurisdictional rate base should be modified to reflect the removal of the PSC assessment, claimed by Union as prepayments, and to reflect the impact of the reduction of the Kentucky income tax on Accumulated Deferred Income Tax.[2]

Utility Plant In Service

1. A 10-year non-AMRP slippage factor of 6.04% should be applied to determine the plant in service in the forecasted test year. This results in a reduction in the forecasted plant in service which in turn reduces the forecasted period depreciation expense and increases the forecasted period net after tax operating income.

The forecasted plant in service should be reduced to reflect the 10-year non-AMRP slippage factor of 6.04%. It is appropriate to use a non-AMRP slippage factor because the plant in service and CWIP projected for the forecasted period for ratemaking purposes in this case are subject to base rate recovery rather than the dollar for dollar accelerated recovery represented by Rider AMRP. The slippage factor arising from the AMRP program is not representative of the slippage for plant subject to base rate recovery because the utility specifically committed to complete its mains replacement program in a timely manner on the accelerated basis in return for favorable rate treatment to recover the cost of that program on an accelerated basis. Construction decisions for plant involved in base rates are not made and implemented under the specific quid pro quo of the AMRP program. The Commission has previously utilized a 10-year average to determine the slippage factor and should continue to do so here. Union has shown no reason a shorter time factor should be used.

---

[2] DT Henkes, pp. 13-14.

Application of this slippage factor reduces the forecasted period depreciation expense by $28,461 and increases the forecasted period net after tax operating income by $17,205.[3] Though depreciation reserve and accumulated deferred income tax balances might be affected by the recommended slippage factor adjustment, the AG does not have the data to make the adjustment, and Union did not comply with requests to make the calculations.

2. The Gas Jurisdictional Rate Base should be decreased by the amount of PSC assessments.

Union includes $105,675 of PSC assessments in rate base, claiming this as a prepayment. The Commission has long refused to consider the PSC assessment a prepayment for ratemaking purposes.[4] Union has presented neither a new nor a previously considered reason to change that long held policy.

3. The Cash Working Capital should be reduced.

Union's claimed cash working capital should be reduced by $101,811 to reflect the lower pro forma test year operation and maintenance expense under the 1/8th formula long utilized by the Commission.[5]

4. Two adjustments should be made to the Accumulated Deferred Income Taxes (ADIT) which result in a net increase in the gas jurisdictional 13-month average net ADIT proposed by Union.

First, the ADIT balance should be reduced to reflect the impact of the reduction in the Kentucky income tax rate from 8.25% to 7.00%, resulting in a $339,459 reduction to Union's proposed 13-month average net ADIT.[6]

---

[3] See Schedule RJH-5; DT Henkes, p, 20.
[4] DT Henkes, pp. 21-22.
[5] DT Henkes, p. 23; RJH Schedule 19.
[6] DT Henkes, pp. 23-24; RJH Schedule 7.

Second, the ADIT balance should be increased to remove the Account 283/284 negative (prepaid) amounts associated with unbilled revenues from the forecasted period gas jurisdictional 13-month average net ADIT balance. This would be commensurate with Union's removal of all unbilled gas revenues from the forecasted test period based on its assumption that all forecasted period gas revenues are from billed revenues only. This increases the ADIT balance by $3,498,304.[7]

The net of these two adjustments increases the forecasted ADIT balance to $36,403,835. This amount acts as a reduction to the jurisdictional gas plant in service and an increase, in the same amount, to the gas non-jurisdictional plant for the calculation of the gas jurisdictional capitalization, as was done in Rebuttal Exhibit WPA-1c.

Pro Forma Operating Income.

Union has accepted seven of the fourteen adjustments recommended by the Attorney General. Those relate to the I&D expense normalization removal; base payroll expense adjustment; the adjustments to gas ADIT balance for the impact of the Kentucky income tax reduction to 7% and for the removal of negative ADIT associated with unbilled revenues; the removal of lobbying expenses, governmental affairs and corporate sponsorship expenses from miscellaneous expenses; correction of the interest synchronization; and, the correction of the ITC adjustment.[8] The following are specific discussions of those adjustments on which the Company and the AG do not agree.

---

[7] DT Henkes, p. 24-26. RJH Schedule 7.

[8] The specifics pertaining those adjustments are found at DT Henkes, pp.27-30 (Kentucky income tax reduction); pp. 34-35 (I&D expense); p.35 (base payroll expense); p. 40 (lobbying, governmental affairs, and corporate sponsorship portion of miscellaneous expenses); pp. 44-46 (interest synchronization); p. 46 (ITC adjustment). Also see, RJH Schedule 8 and supporting schedules.

1. The Commission should continue to use the 30-year norm for Union's weather normalization adjustment.

Union again restates its forecasted period sales based on a 10-year norm ending in 2000. Union's contention that the use of a 10-year normalization is appropriate was made in its last rate case. It was discussed and rejected based on the extreme volatility that results from the use of such shorter periods. After demonstrating the volatility provoked by the utilization of only one year over another when using a ten-year average, the Commission said:

> ULH&P's proposal to use a shorter historical period in calculating its adjustment demonstrates that such periods can result in greater volatility in determining an average number of heating degree days. The use of an updated 30-year period adequately reflects the trend of warmer winters with fewer heating degree days while effectively limiting the type of volatility that can occur when shorter periods are used.[9]

In that Order, the Commission discussed the need for Union to fully support its request for a change from the Commission's previous means of dealing with an expense in its case in chief. Union again has failed to show that the use of the shorter normalization period provides results that are so much more representative of the norm than those of the 30-year normalization period that the results should be used. A strong showing would be required to overcome the demonstrated inherent volatility of results presented by the use of the shorter period. Moreover, it did not even offer to use the most recent 10-year period in establishing its normalization. It again used the period whose volatility was demonstrated by the Commission in the Rehearing Order that rejected the 10-year norm based on inherent volatility.

Instead, the Commission should use the 30-year period ending 2004 and the revised NOAA data to normalize the forecasted period sales.[10] The revised NOAA 30-year norm more closely reflects the weather experienced in recent years. This alone supports its continued usage.

---

[9] In the Matter of: Adjustment of Gas Rates of the Union Light, Heat and power Company, Case No. 2001-00092, 13 March 2002 Order on Rehearing, p. 15.

[10] DT David Brown Kinloch (Brown Kinloch), p. 5.

Further, because it is less susceptible to volatility, it prevents the kind of shopping for a 10-year period done by Union. The 10-years chosen to be representative by Union were not the most recent ten years, thus belying the assertion that the period should be short to reflect recent weather trends. The ten years chosen by Union did, however, cover the period that produced the lowest HDD result.[11]

Union's weather normalization calculations were also in error in their reliance on NOAA preliminary data, data that was later revised to improve its accuracy.[12]

Use of the 30-normal with revised NOAA data for Covington produces a HDD norm of 5,133, which is 183 HDD greater than that proposed by Union. Utilizing the information provided by Union, this produces an increase in revenues of $731,516. Following adjustments for the impact of that increase on uncollectibles and on the PSC assessment, and using the after tax rate, the impact on operating income is an increase of $415,500.[13]

2. The Commission should recognize mild growth in Firm Transportation volumes in the forecasted test year rather than accepting the accepting the 26.6% decrease in those volumes proposed by Union.

Union has projected that Firm Transportation volumes will drop by 26.6% in the twenty three months between the actual historic test year and the forecast test year based on the assumption that it will lose 3 customers all together, resulting in a total of 51 customers and, will see decreases in volume for those customers who remain due to the dramatic increases in the price of gas.

Neither projection matches the current experience for Union. Since the historic test year, it has gained 3 customers. Further, contrary to Union's model, it has seen growth in volume

[11] DT Brown Kinloch, pp. 6-7.
[12] DT Brown Kinloch, pp. 4-5.
[13] DT Henkes, pp. 31-33.

during the time that prices were increasing and declines in volume when prices were decreasing, which indicates that the link between gas prices and volumes is not what Union has projected.[14]

Conservatively, the Commission should assume that there will be 55 firm transportation customers as that is the number of customers at the end of the historic test year. Despite enormous increases in the price of gas, volumes increased 15% in 2003 and 9% in 2004.[15] This increase in volume was probably in response to the end of the 2002 recession and continued economic improvement. Applying a 9.08% growth rate produces a base revenue adjustment of $1,148,833. After that figure is adjusted for uncollectibles, PSC maintenance fees and taxes, it increases operating income by $685,073.[16]

3. If the Commission adopts the Attorney General's Position with reference to bad check and reconnection fees, Union's pro forma income will be lower.

As will be discussed in further detail in the rate design section, the AG recommends that: (a) the Commission refuse to grant Union's proposed increase in bad check fees because they are unsupported by any proof of the cost to Union for processing a bad check; and (b) that the reconnection fee be increased by a percentage no greater than the overall percent increase allowed by the Commission in this case.[17] Adoption of these recommendations will reduce Union's pro forma operating income.[18]

4. The Commission should refuse to allow recovery of any incentive compensation under any of Union's incentive compensation plans.

Union proposed an adjustment to allow it to recover 100% of the gas allocated share of its three incentive compensation programs from ratepayers. In its rebuttal, Union changed its proposal so that 50% of its Long Term Incentive Plan (LTIP) would be shared between

---

[14] DT Brown Kinloch, pp. 8-11.
[15] Id.
[16] DT Henkes, p. 33; RJH Schedule 10.
[17] DT Brown Kinloch, pp. 20-22.
[18] DT Henkes, p. 34.

shareholders and ratepayers,[19] there would be a 75%/25% ratepayer/shareholder sharing of its Annual Incentive Plan (AIP), and ratepayers would bear 100% of the Union Employees Incentive Plan (UEIP).[20]

Union has again provided evidence that shows that the specified performance criteria of all of the incentive plans place more weight on the interest of the shareholders than they place on the ratepayers.[21] Union has again offered testimony that its incentive plans motivate its employees to perform at high levels and to place customer service and satisfaction at the forefront of its efforts. Union has again failed to present any quantitative proof in support of this claim. The only quantitative proof it could submit was that a study had found that 70% of the participating organizations report that variable pay was important to the success of their organizations' "competitive strategy." As a regulated entity, that goal is unimportant to Union.

Union has presented testimony that incentive plans are common in the industry and that its plans are in alignment with the industry. It has stated that customers benefit from the plans' performance objective based on financial metrics such as net income, because it is in customers' interest to have a financially sound utility, which in turn will ostensibly enhance the utility's ability to provide safe, adequate and reliable service by allowing it better access to the financial resources that will allow it the make those capital operational expenditures. It also states that these plans are necessary to attract and retrain reliable employees.[22]

These same claims were made by Kentucky-American with reference to its incentive compensation plans. Despite the fact that the AG recommended that ratepayers share some of the expense of the incentive plan, the Commission found that proof provided by Kentucky-

[19] TE Vol. II, p.76.
[20] TE Vol. II, pp. 84-85.
[21] DT Vol. II, pp. 36-39.
[22] Rebuttal Testimony Robert C. Lesuer, pp. 3-4; TE Vol. II, p. 87.

American, which is like in nature and emphasis to that provided by Union, was insufficient to warrant the collection of any of the incentive compensation cost from ratepayers. This was the second time the Commission disallowed Kentucky-American's request for sharing of the incentive costs and followed a history that had previously allowed Kentucky-American full recovery of incentive compensation in its rates.[23] Unlike Kentucky-American, Union has never been allowed recovery of incentive compensation in its rates. As Union's proof is like that offered by Kentucky-American, the incentive compensation should be excluded from rates in this case too.

5. The Commission should reduce Union's claimed depreciation expense to recognize certain changes in the service lives and net salvage proposed by Union. The changes reduce the depreciation expense by $1.9 million rather than the reduction of $270 thousand proposed by Union.

On behalf of the AG, Mr. Mike Majoros reviewed Union's depreciation study. He addressed several problematic recommendations in Union's study which are set out specifically below. The sum total of the depreciation reduction that is appropriate is $1.9 million rather than the $270 thousand reduction proposed by Union.[24]

The AG recommends certain changes in the depreciation study itself and the corresponding changes in the depreciation expense. The AG also recommends certain policy changes in the reporting requirements for Union and in the treatment of accumulated depreciation on a going forward basis. Those changes are discussed later.

---

[23] In the Matter of: Adjustments of the Rates of Kentucky-American Water Company, 28 February 2005 Order, pp. 37-39.

[24] DT Michael J. Majoros, Jr. (Majoros), pp. 4-5.

5.1 Account 2050 – Production Plant Structures and Improvements

In his direct testimony, Mr. Spanos presented an estimate of the average service life for this account of 50 years, which is an increase over the 45-year average service life utilized in ULH&P's last depreciation study, and results in a remaining life of 41.2 years. His life analysis demonstrates a long life indication compared to his proposed use of 50-R4 for the account.[25] When asked whether an Iowa curve providing a better match for the account exists, he replied that it did not and that his selection is a judgment call based on the nature of the assets, the past estimate for this account and the estimates by other utilities.[26] Subsequently, he explained that this account consists of pre-fabricated steel buildings initially constructed in 1961, and opined that the statistical analysis of service life for this account is indeterminate because though the asset behaves like a mass property, historical data for the single station does not generate sufficient retirement data to be conclusive, which is why he turned to the estimates of other utilities as the basis for his judgment.[27]

Mr. Majoros performed an analysis which found that the R4 Iowa curve is the best fit, but the average life should be 83 years rather than 50 years.[28] The impact of this finding on the recommended remaining life for this account is an additional 3 years, moving from 41.2 to 44.4 years remaining life.

On cross examination much was made of the maximum life involved in Majoros' analysis, with expressions of disbelief that maintained steel buildings would achieve a life of 120 years before requiring replacement.[29] Given that adobe and marble walls constructed thousands of years ago are still standing with little or no maintenance and that maintained brick and stone

---

[25] DT Majoros, pp. 8-9.
[26] ULH&P Response to KyPSC-02-012.
[27] Spanos Rebuttal, p. 30.
[28] DT Majoros, pp. 9-10; Exhibit__(MJM-5), compare page 3 and 5 with reference to match.
[29] TE Vol. II, pp. 46-47.

buildings dating back hundreds of years are in regular use, this disbelief is disingenuous. Furthermore, the 120 year figure were is a statistical smokescreen. Exhibit___(MJM-5), page 8 demonstrates that the longest remaining life assumed for the 83-R4 curve is 77.44 years for the very youngest (0.5) age group. The assets in this account include manufactured steel buildings.[30] The additional three years of remaining life resulting from Mr. Majoros' analysis are realistic.

5.2 Account 2210 – Liquid Petroleum Gas Equipment

Mr. Spanos recommends no change in the parameters of a 35-year average service life and a net salvage factor of negative 5 percent for this account from the depreciation study presented in Union's last rate case. The life and curve combination result in a 23.7 year remaining life.

This small account is comprised of the pumps, boilers, tanks, compressors, piping, valves, vaporizers and regulators and other items at the Erlanger Station peak shaving facilities.[31] When asked if there was not a better fit curve that would lower the 2.45% rate the Company proposes for this account, Mr. Spanos responded that while there were better statistical matches, he settled on this one because of the characteristics of the assets and the fact that the life and curve he used is comparable to the estimates of other <u>electric</u> utilities. This study, of course, does not pertain to Union's electric operations.

Mr. Majoros did an analysis that shows that the best fit is a 100 R0.5 life and curve rather than the 35 S1.5 curve proposed by Union. He also found that for the S1.5 curve, the curve proposed by Union, the best fit life indication is 59 years.[32] Much again was made of how long the maximum life associated with this choice is, but its statistical fit went unchallenged.

[30] Exhibit___(MJM-5) page 8 of 9 Corrected.
[31] Spanos Rebuttal, p.30; TE Vol. II, pp. 47.
[32] TE Vol. II, pp. 46-48.

Furthermore, the maximum remaining life resulting from the 59-R1.5 curve is only 48.48 years for the youngest (0.5) age group.[33] The 51-S1.5 life and curve represents a better fit and does lower the depreciation rate. The remaining life under this life and curve for this account is 37.6 years.

5.3 Account 2741-Rights of Way

In his direct testimony, Mr. Spanos presented an estimate of the service life for Rights of Way of 65-R4 that shifts inward while the data points are straight line. In response to staff questions he explained that there is no Iowa curve that will statistically match the Rights of Way account, so his selection was based on the nature of the assets, his past estimates for the account and the estimates of other utilities with similar assets.[34] Mr. Spanos further explained that the right-of-way life ought to be considered in light of and limited by the maximum life of the main to be placed there in arriving at the judgment for rights of way. He pointed out the maximum lives for steel mains as a limiting factor.[35] This method produces a remaining life of 40.8 years.

In the clarification of the process of removal and the tie-in of new mains in conjunction with the allocation of pricing, Mr. Hebbler explained that retired mains are not removed, but purged and capped in place through the use of a single tie-in hole from which the new main is tied-in and the old main is purged and capped.[36] This comports with Mr. Spanos' description of the Company's practice which has gone from removal to retirement in place with insertion of new mains into the old mains, to retirement in place in which the old mains are purged, capped

---

[33] See, Exhibit__(MJM-6), p. 8.
[34] ULH&P Response to KyPSC-02-014.
[35] Spanos Rebuttal, pp. 31-32.
[36] ULH&P Responses to AG-01-30 and -32; KyPSC 03-052 d.

and abandoned, when the adjacent new mains are tied-in.[37] Under all but the scenario in which mains are removed, it is obvious that right of ways are used and re-used. Therefore, limiting their life to by the maximum life of any given main fails to reflect their general duration of use and runs counter to the assertion that the shorter life is based on the nature of the assets.

Mr. Majoros performed an independent analysis which has an upper limit of 100 years. Based on the insignificant retirement activity in the account and the nature of the assets, he recommends the use of a 100-R4 life/curve for the account, resulting in a remaining life of 70.4 years. This recommendation more closely reflects the perpetual use and re-use of right of ways and should be adopted by the Commission despite the fact Mr. Spanos' unchallenged study in the preceding rate case used the same service live and remaining life proposed here.

5.4 Account 2763 – Distribution Plant Mains – Plastic

Based on the fact that plastic mains have only been abound for 39 years, Mr. Spanos proposed use of a 50-year average service life and a net salvage factor of negative 20 percent. This results in a 36.3 year remaining life for plastic mains. When staff asked whether this remaining life was not overly conservative, and whether there is an Iowa curve that would provide a better match, Mr. Spanos responded that this choice was a judgment call based on factors beyond statistics that included the fact that retirements to date mimic the pre-average life retirement of steel mains. These are factors that have nothing to do with age related failures or reduction in safety.[38]

Given that Union is in the midst of replacing all of its cast iron and bare steel pipe with plastic under a program that was granted in part because of the purported superiority of plastic

[37] Spanos Rebuttal, pp. 34.
[38] ULH&P response to KyPSC-02-015; Spanos Rebuttal, p.33.

over steel (because it is not susceptible to things such as corrosion and is capable of withstanding greater pressure) it is truly disappointing that Union now indicates through its depreciation proposal that the accelerated replacement program it is pursuing with such vigor is installing mains that are no better than those being replaced. The AG is optimistic that plastic will perform as touted in the development of the AMRP. In combination with the statistical fit his study produced, the statistical accuracy of which is not challenged by Union, Mr. Majoros proposes and the AG recommends a curve and life of 70-R1.5, resulting in a 44.3 year remaining life.[39]

5.5 Accounts 2761 and 2801 – Distribution Plant Mains and Services - Cast Iron, Copper and All Valves

These accounts are both subject to the AMRP program which is scheduled for completion in 2010, 6 years after the date of this depreciation study. Based on the common sense approach of matching actual removal under the program with the end of the service lives, Mr. Majoros proposed a remaining life of 6 years for both accounts. By shortening the proposed service life for these accounts, Mr. Majoros is recommending an increase in those rates.

He also recommends a zero percent net salvage factor for these accounts because the cost of removal for the accounts is a small proportion of the overall replacement expenditures, because it is not clear that the net salvage proposed by Union for services relates to these types of services and because the two accounts are over-depreciated by $443,000.[40]

5.6 Account 2760 – Distribution Mains net Salvage

Rather than using the 20% negative net salvage proposed by Union for all mains sub-accounts, the Commission should use zero net salvage for the cast iron mains and a 5% negative

[39] DT Majoros, p. 16, Exhibit__(MJM-9).
[40] DT Majoros, p.14.

net salvage for Steel and Plastic Mains. Union's reason for the use of the substantially higher net salvage is the drop in gross salvage arising from the implementation of increased use of horizontal directional drilling rather than insertion of new mains into old ones.[41]

The problems in the accounts are the levels of cost of removal as compared to additions and/or plant balances, not retirements. The average cost of removal that Mr. Spanos compared to the total average retirements during the last five years are very small amounts when compared to annual plant balances, yet it is the much larger annual plant balance to which the negative 20% net savage will then be applied for the calculation of the depreciation rate. This overstates the depreciation charge. Not only is the 5% negative net salvage historically representative, it is based on Union's own summary. The 5% negative net salvage should be used.

5.7 Account 2801 – Distribution Services – net salvage

Union proposes a negative 35% net salvage ratio for all the Services sub-accounts. A zero net salvage should be used for the Cast Iron Service subject to the AMRP, and a 5% negative net salvage should be used for all other Distribution Services sub-accounts. Based on responses to data requests, the net salvage data used by Union relates to abandoned services that were not removed because they were associated with abandoned residences. The 35% negative net salvage they produce is not representative and should not be used. The 5% negative net salvage should be used for Services.

6. A slippage adjustment of $17,205 is required.

For the reasons set out in the discussion of slippage in the plant in service section of this brief, operating income should be reduced by $17,205.[42]

[41] Spanos Rebuttal, pp. 34-35.

7. The forecasted test year period property taxes should be reduced by $535,245.

In the Notice of Assessment provided to the AG on September 16, 2005, it appears that Union as been at least equally as successful in negotiating assessment values below book value with the Kentucky Revenue Department as it was in the last three years. Therefore, the forecasted test period property tax assumption predicated on the assumed inability to successfully negotiate a reduced assessment should be reduced by $535,245.[43]

COST OF CAPITAL

OVERVIEW

Like all other utilities operating in Kentucky, ULH&P may demand rates that are "fair, just and reasonable" for its provision of service. KRS 289.030(1). "Rates are non-confiscatory, just and reasonable so long as they enable the utility to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed even though they might produce only a meager return on the so-called 'fair value' rate base." *Com. Ex Rel. Stephens v. So. Cent. Bell Tel. Co*, 545 S.W.2d 927, 930-931 (Ky. 1976) citing *Federal Power Commissions v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1943).

Under this standard, rates provide the opportunity for the utility to compensate its investors, but do not guarantee they will do so. Investors assume the risk. Ratepayers have no responsibility to indemnify investors against the risks they have elected to assume.

---

[42] See Sch. RJH-5.
[43] DT Henkes, pp. 42-44.

CAPITAL STRUCTURE

Union has proposed a capital structure that contains 54.45% common equity. Dr. Woolridge performed a study which shows that that average common equity ratio within the capital structure for publicly-traded gas distribution companies is 46.2. At 54.45%, Union's proposed common equity ratio is significantly higher than that of other gas distribution companies. This causes Union to have less financial risk.[44]

Though Union did not rebut the fact that it has proposed a significantly higher common equity ratio and that this serves to reduce financial risk, it did nothing to reflect that reduced risk in its proposed return on equity.

In Union's cross-examination of Dr. Woolridge designed to show that Union's proposed return is in line with past Commission allowed returns, it became evident that not only were those returns awarded when the cost of capital was greater than it is today, but also that the ratio of common equity in the capital structures of the companies to which the returns were awarded were, as also shown by Dr. Woolridge's study, in the range of 46.2%.[45] Union's proposed 54.45% common equity ratio is well above the norm. The AG is adopting Union's proposed capital structure rather than proposing a more economical capital structure more in line with that found in the gas distribution industry.[46] This risk reducing accommodation, and Union's failure to account for that risk reduction in its requested return on equity, should be considered in determining the appropriate return on common equity to be awarded to Union.

[44] DT Dr. J. Randall Woolridge (Woolridge), p. 9.
[45] TE Vol. II, p. 136.
[46] DT Woolridge, p. 3.

RETURN ON COMMON EQUITY

1. The appropriate return on Common Equity for Union's gas is 8.7%.

In both its rebuttal testimony and its cross-examination of Dr. Woolridge, Union has strongly beaten the drum of maintaining for Union, on a going forward basis, a return on common equity commensurate with those returns that have been achieved or allowed by Commissions for other gas, gas and electric, or electric utilities in decisions made ranging from 6 months to five or six years ago.[47] It has castigated Dr. Woolridge's conclusion that in today's economic environment a return of 8.7% is fair, just, and reasonable because it falls outside the range of historically awarded returns. While Dr. Woolridge's recommendation is below the historically awarded returns to which Union has pointed, it is nevertheless fully justified by the economic conditions prevailing for this utility in this case based on this test period where long term interest rates and the equity risk premium are the lowest they have been in the last forty years and where changes in the 2003 tax law have reduced the pre-tax requirements of investors.[48]

Despite continued predictions that long term interest rates will rise, long term interest rates remain in the 4.5 range. Equity risk premiums have fallen from the 5-7% that prevailed based on historic analysis, in which underlying data was based on company performance and information available to investors at the pace of 1926 forward, to a forward-looking equity risk premium of 3-4% based on multiple factors, not the least of which is permanent technological change in the information available to examine and manage risk. Permanent technological changes make information available to investors for the first time at speeds and with levels of

[47] TE Vol. II, p. 150-152, 137-148.
[48] DT Woolridge, pp.2-7.

specificity not previously imagined and not taken into account in the historic risk premium approach.[49]

To develop a fair return for Union, Dr. Woolridge performed both a discounted case flow study (DCF) and a Capital Asset Pricing Model (CAPM) study. The results of the CAPM, a version of the less reliable risk premium study, have been given less weight than the 8.7% result of the DCF study by Dr. Woolridge.

In developing the rate of return, Dr. Woolridge evaluated the return requirements of investors in the common stock of publicly-held gas distribution companies by creating an eleven company proxy group consisting of all gas distribution companies from the *Value Line Investment Survey* that receive at least 50% of their revenues from natural gas distribution, pay a dividend, and have debt that is rated BBB or better by Standard & Poor's.[50]

To perform a DCF study, it is necessary to have a dividend yield and an expected growth rate. Dr. Woolridge used the average DCF dividend yield for the proxy group of 4.35%.[51] This yield was adjusted by ½ the expected growth in order to reflect growth for the coming year.[52] This produces an adjusted dividend yield of 4.44%.[53]

To derive a growth rate for use in his DCF study, Dr. Woolridge looked both at historic growth rates and analysts' forecasts of expected growth for the proxy group. Based on that information, he used a growth rate of 4.25% for his DCF.[54] When added to the adjusted dividend yield, this results in an equity cost rate of 8.7%. This analysis is the basis for the Attorney General's recommendation of an equity cost rate of 8.7%.

---

[49] Id.
[50] DT Woolridge, p. 7-8.
[51] DT Woolridge, p. 20.
[52] DT Woolridge, p. 21.
[53] Exhibit_(JRW-7), p. 1.
[54] DT Woolridge, pp. 21-25.

As a variant of the risk premium study, the CAPM develops capital cost by applying a risk premium to a risk-free rate. This requires three inputs: the risk-free rate, the beta or measure of systematic risk, and the equity or market risk premium. The risk-free rate is the yield on 10-year Treasury bonds. In this case a 4.5% yield reflects the upper end of the range of yield during the last year and was used by Dr. Woolridge.[55]

Beta measures how stock price for a company moves with the market and thereby reflects its systematic risk. A stock that moves with the same price movement in the market has a beta of 1.0, the same beta as the market. A stock whose price moves more than the market is considered more risky than the market and has a beta greater than 1.0 and a stock whose price moves less than the market is considered less risky than the market and has a beta less than 1.0. Betas are reported by various services, but may differ both because of the time period measured in the report or the adjustments made to reflect their tendency to regress toward 1.0 over time. In his CAPM study, Dr. Woolridge used the average betas for the proxy group gas distribution companies of .76 provided in the *Value Line Investments Survey*. [56]

The determination of the risk premium is the most controversial aspect of the CAPM. Some develop the premium as the difference between historic average stock and bond returns, an approach that is fraught with difficulties[57] which produces a risk premium of 5-7%. Others develop the *ex ante* risk premium using fundamental firm data, which produces lower estimates with an average of 4.0%.[58] Dr. Woolridge used both an equity risk premium that is the average of the *ex ante* expected equity risk premiums from the studies covered in the 2003 Derrig and Orr study and an *ex ante* expected equity risk premium developed using Ibbotson and Chen's

---

[55] DT Woolridge, p. 27.
[56] DT Woolridge, pp. 28-30.
[57] These are discussed in detail in the brief beginning at page 23.
[58] DT Woolridge, pp. 30-34.

"building block methodology." The building block method bridges the gap between *ex post* and *ex ante* equity risk premiums by relating the historic return to different fundamental variables used to build *ex ante* premiums. It produced an expected market return of 7.9%. This produces a risk premium of 3.4%, which, when averaged with the 4.0% of the Derrig and Orr study, results in an equity risk premium of 3.7% for use as the final input in the CAPM.[59] The final result of the CAPM is 7.31%.[60]

The AG's recommendation is the 8.7% produced by the DCF study. Though lower than that we are accustomed to seeing, it is fair and appropriate given that current capital costs are low by historic standards based on the lowest interest rates seen since the 1960s, that the 2003 tax law lowers the pre-tax return required by investors, and that the equity risk premium has declined.[61]

2. Union's Analysis is not reliable.

On behalf of Union, Dr. Roger Morin performed a Cost of Capital Analysis that included a DCF approach, a CAPM and ECAPM approach, two historic risk premium approaches and an allowed risk premium approach. At the hearing, Dr. Morin lowered his originally recommended Rate of Return of 11.2% by forty basis points to 10.8% to reflect the continued downward trends in the cost of capital since his direct testimony had been filed.[62] While that is a welcome step in the right direction given that the cost of capital is at the lowest it has been for many years, Dr. Morin's study is flawed, and therefore, not reliable. The four main flaws in his analysis are: (1) his use of inflated forecasted interest rates in which the forecasted risk-free rate of interest is well

[59] DT Woolridge, pp.34-42.
[60] DT Woolridge, p. 45.
[61] DT Woolridge, pp. 4-7.
[62] TE Vol. II, p. 60.

in excess of the current long-term interest rates; (2) excessive risk premiums; (3) the use of unduly high DCF analysts' growth rates; and, (4) the inclusion of flotation costs.

Dr. Morin's analysis used a DCF approach and several variants on the risk premium approach. The risk premium approaches include the CAPM, the ECAPM, two historic and one Allowed Risk Premium approach.

All of these approaches have some common elements, among which is the inclusion of flotation costs. Inclusion of flotation costs for a utility that has had no infusion of capital for more than five years past, and has no plans for infusions of capital for its gas business,[63] overstates capital cost based on phantom expense the utility has not incurred in the recent past and will not incur in the foreseeable future.[64] Inclusion of a flotation adjustment for a utility that does not issue stock in equity markets is contrary to Commission precedent.[65]

In his on-the-stand correction to and reduction of his recommended rate of return, Dr. Morin stated that the basis for the revised recommendation was to reflect the continued decrease in interest rates. In so doing he addressed the second of the flaws common to his various approaches by reducing the projected interest from the 5.2% to 5.9% range to the 4.5% to 5.0% range.[66] This correction also highlights the unreliability of forecasts for interest rates, where predictions exceed reality and where returns granted based on those predictions become windfalls to the utility.

The third of the flaws common to the CAPM analysis and the historic risk premium approaches is the inflated expected risk premium that is derived from the use of historic stock

---

[63] The only planned equity infusion is associated with the transfer of electric generating assets from CG&E to ULH&P.

[64] DT Woolridge, pp. 55-56.

[65] In the Matter of: The Application of Kentucky Power Company d/b/a American Electric Power Company for Approval of an Amended Compliance Plan for Purposes of Recovering the Cost of New and Additional Pollution Control Facilities and to Amend its Environmental Cost Recovery Surcharge, Case No. 2002-00169, Order 31 March 2003, p. 32..

[66] TE Vol. II, pp.59-60.

and bond returns to compute a future expected risk premium. Use of the historic relationship between stock and bond returns to measure an *ex ante* equity risk premium overstates the true market equity risk premium because past market conditions vary significantly from the present market conditions. The historic data does not provide an accurate picture of the expectations for the future, the condition the *ex ante* risk premium is modeling.[67]

Use of historic returns covering a long period of time to estimate expected equity risk premiums relies upon a host of problematic assumptions and produces questionable results. First, it assumes that over long periods of time investors' expectations are realized, though that is not the case. Because of the capital losses actually experienced by bondholders in the past, that assumption places a downward bias on historic bond returns and results in risk premiums that are biased upward.[68]

Next, it uses arithmetic mean returns despite the fact that the study covers more than one time period and assumes that dividends are being reinvested. Under these circumstances, the geometric mean should be used.[69] Use of the arithmetic means produces an upward bias, a questionable result.

Third, it is based on returns that cannot be attained by investors and produces biased results because of its assumption of monthly portfolio rebalancing, a practice that would involve transaction costs that would reduce the actual return to the investor below the reported return. For the same reason, the payment of transaction costs associated with stock transactions, historic returns do not reflect the actual return experienced by the investor. Because those transactions

[67] DT Woolridge, p. 58.
[68] DT Woolridge, p. 59.
[69] Id. at pp. 60-61.

costs were higher historically than they are today, there is a further bias built into reliance on the reported historic returns.[70]

Fourth it fails to note that some corporations did not survive or continue to perform at a level that would continue their inclusion in indexes like the S&P 500, so that when historic data using returns from indexes is used to estimate an equity risk premium, the returns are upwardly biased, reflecting the returns only of the most successful of the investments out there.[71]

Fifth, because past stock market returns have been higher than expected at the time despite the presence of factors like wars or the depression, improbable events are factored into stock prices, causing seemingly low valuations. When those events do not occur, higher than expected returns are earned, causing historic stock returns to be overstated in comparison to expected future returns.[72]

Next, as measured by the price earnings ratio, stock valuations are relatively high while interest rates are relatively low, which means that expected returns on a going forward basis are likely to be lower than they were when valuations were low and/or interest rates were high.[73]

Most importantly, the use of historic returns to measure future equity risk premiums blurs the impact of the change in the risk and return relationship between stocks and bond in the past 10-15 years in which bonds have increased in risk in comparison to stocks causing a decrease in the equity risk premiums.[74]

Dr. Morin's forecasted equity risk premium, used in his CAPM and ECAPM approaches, is also over inflated. It is based on DPS growth rates of 10.7% and EPS growth rates of 13.2% taken from *Value Line's* 5-year growth rates for all stocks on which projections were made.

[70] DT Woolridge, pp. 61-62.
[71] DT Woolridge, p. 62.
[72] DT Woolridge, p. 63.
[73] DT Woolridge, p. 63.
[74] DT Woolridge pp. 64-65.

These growth rates are substantially higher than the 7% long-term economic and earnings growth rate in the U.S. They are also substantially higher than the approximate 7% growth in S&P500 from 1960 to date. The forecasted expected market return of 13.4% derived from the 10.7% and 13.2% DPS and EPS growth rates used by Dr. Morin require an expectation that companies in the U.S. will have to double their EPS and DPS in the future and sustain that added growth in an economy that is expected to grow at only half of Dr. Morin's projected growth rate.[75] This is far from realistic. It does not provide a reasonable basis upon which to base Union's rate of return.

Dr. Morin cites a study by Harris, Marston, Mishra, and O'Brien as a checkpoint to support his overall equity risk premium. That study develops an expected market return using analysts' expected EPS forecasts as measures of expected growth in the DCF model. Dr. Morin agreed that the studies upon which he relied pre-date the recognition of analysts' bias in stock research.[76] That bias is a significant upward bias.[77] Use of upwardly biased analysts' estimates in a DCF model produces inflated expected market returns and equity risk premiums.[78]

The results of Dr. Morin's DCF studies are also unreliable because of their reliance solely on analysts' forecasts of EPS growth. Not only have the analysts' EPS growth forecasts been proven suspect through the work of Elliot Spitzer, Dr. Woolridge's study, which compares actual 3-5 year EPS growth rates with forecasted EPS growth rates on a quarterly basis over the past 20 plus years, confirms that the bias is an upward bias. The upward bias is significant at all times other than the one year economic downturn in 1991-92.[79]

For these reasons, Dr. Morin's analysis is unreliable and should not be the basis for return on common equity for Union in this case.

---

[75] DT Woolridge, pp. 67-69.
[76] TE. Vol. II, pp. 96-97.
[77] DT Woolridge, pp. 74-78
[78] DT Woolridge, p. 69-70.
[79] DT Woolridge, DT 73-78.

COST OF SERVICE

Three problems in Union's cost of service study need to be corrected. The first two relate to sales volumes and demand that impact the allocation of costs between rate classes. The first is the use of a 10-year weather normalization factor rather than a 30-year normalization factor based on updated NOAA data for the Covington area. The second is the unduly pessimistic forecast for a decline in Firm Transportation volumes.

The reason the Commission should continue using a 30-year normalization factor based on updated data for the Covington area is set out in full above in the discussion of the impact of corrected normalized sales volumes on operating income. That result is 5,133 HDD rather than the 4,950 HDD used by Union.[80] Mr. Brown Kinloch used the 5,133 HDD to correct the volumes and demands in the Cost of Service study.

The error in Union's use of a forecast 26.6% reduction in Firm Transportation volumes is discussed in full in connection with the corrected firm transportation volumes on operating income. Mr. Brown Kinloch corrected the historic test year to reflect weather normalized volumes using a 30-year normalization and applied the most recent growth rate of 9.08% to the 23 months between the historic and forecast test period. This produced the Firm Transportation volumes of 1,661,556[81] then transferred into the Cost of Service study. The revenue impacts of the corrected Firm Transportation volumes were also calculated.

In Exhibit DBHK-10, the corrected volumes and associated demands are included in the "Peak & Average-Peak Day" allocator in the Cost of Service study.

The third problem in the Cost of Service Study is the development of the allocator for regulators. ULH&P used a complicated weighting scheme that results in charging 83,852

[80] DT David H. Brown Kinloch (Brown Kinloch), p. 6, 8.
[81] DT Brown Kinloch, p. 11; Exhibit DHBK-8.

regulators to the residential class when there are only 52,559 residential regulators. As a class that has but one rate, weighting is not necessary for the residential class. The regulator cost for this class is known and should be allocated to the class directly. Weighting is necessary to allocate the regulator cost to the commercial and industrial customers that are a part of three rate classes.[82]

The corrected allocators were substituted in the ULH&P Cost of Service study for ULH&P's incorrect allocators. The class revenues were changed to reflect the proposed changes in gas volumes. The Cost of Service study including these corrections is found in Exhibit DHBK-13.

ULH&P's proposed allocation methodology is not reasonable or fair in its assignment of over 90% of the rate increase to the residential class. The ULH&P allocation method begins with capitalization rather than present revenues, which results in the assignment of over 72% of the increase to residential rather than the 65% that would be assigned using present revenues. The assignment of another 18% of the rate increase to the residential class is designed to eliminate the subsidization of the class' failure to make its full contribution to rate of return.

Starting with an allocation of the rate increase based on present revenues and moving the class contributions closer to their contribution to rate of return as shown by the Cost of Service study more gradually presents a more reasonable result. Because ULH&P is proposing a movement of 1/3rd towards cost of service for customer charges, the AG recommends a like movement of 1/3rd for allocation of the rate increase. Under this allocation, the residential class would be allocated 77.2% of the increase, General Service would be allocated 20.82%, Firm

---

[82] DT Brown Kinloch, pp. 12-13.

Transportation would be allocated 1.5% and Interruptible Transportation would be allocated 0.5%.[83] This is not only reasonable, but comports with the policy of Gradualism and Continuity.

RATE DESIGN

1. Customer Charge

Though the approach used by ULH&P in the development of the monthly customer charge is somewhat unorthodox, the major problem is the proposal to collect all costs labeled customer costs in the customer charge regardless of whether the costs so-labeled are more likely to vary with the amount of gas sold than with the number of customers served. Costs that vary more with the amount of gas sold than with the number of customers served should be collected as a part of the commodity charge according to the NARUC <u>Gas Distribution Rate Design Manual.</u> Uncollectibles are an example of costs more likely to vary with the amount of commodity used that are labeled customer costs. Distribution mains are another. Neither should be included in the customer charge.[84] Instead, their cost should be recovered on a volumetric basis.

Based on the addition of the AG's Cost of Service study to ULH&P's class functionalization for the Residential class produces an indicated customer charge of $15.29. Moving 1/3rd of the way from the current customer charge of $8.30 for the Residential class to the indicated Cost of Service customer charge of $15.29 produces a recommended Residential Customer Charge of $10.63 per month.[85] This Customer Charge is higher than the Customer Charge of all other large gas distribution companies in Kentucky.[86]

[83] DT Brown Kinloch, p. 15.
[84] DT Brown Kinloch, pp. 17-18.
[85] DT Brown Kinloch, pp. 17-18.
[86] DT Brown Kinloch, pp. 18-19.

Using the same methodology to determine the increase in the Customer Charge that should be implemented produces a recommended Customer Charge for the General Services class of $22.84 per month. This charge too is higher than the Customer Charge of any other major gas distribution utility in Kentucky, but not markedly so. This stands in contrast to ULH&P's proposal which would increase the General Service Customer Charge by 150%, an increase that violates the principles of continuity and gradualism.[87]

2. Miscellaneous Charges – Bad Check Charge

ULH&P proposes an increase in the bad check charge without information to support that charge on a cost of service basis. The rationale is that the charge is more consistent with that charged by other businesses, businesses that are not regulated. Unregulated businesses do not operate on a cost of service basis. To the extent that the underlying rationale for the amount of the bad check charge is deterrent or penalty rather than the cost of dealing with a bad check,[88] other customers of the utility are subsidized by the amounts of those unsupported penalties or deterrents. Granted, some who write bad checks have little excuse. More often, they are those with the most marginal income. Subsidizing the rates of other customers on the backs of those with the most marginal income is wrong. The bad check charge should collect the cost of processing the check, but nothing more. Absent proof of added cost, the bad check charge should be left at $11.00.

---

[87] DT Brown Kinloch, pp. 19-20.
[88] DT Brown Kinloch, pp. 20-21.

3. Miscellaneous Charges – Reconnection Fee

ULH&P proposes a 67% increase in the Reconnection Fee, increasing the fee from $15.00 to $25.00. Reconnect fees are burdens to already financially strained customers who are disconnected. Though they are directly responsible for the cost, their ability to pay it may well be limited. Therefore, it is appropriate to use the principles of gradualism and continuity in the increase of the reconnection fee. The AG recommends that the Reconnection fee be increased by no more than the percent of the general rate increase. This produces a gas-only increase of $15.41 and a combined Reconnection fee of $21.57.

RIDER AMRP

1. Because statutory authority to engage in single-issue ratemaking between rate cases for the mains replacement costs of gas distribution companies is lacking, the Commission should refuse to establish a new Rider AMRP.

ULH&P seeks a new Rider AMRP to allow it to recover costs incurred after the close of the test year for this case and annual costs incurred thereafter until the next rate case to provide the financial support for the continuation of its AMRP. The newly proposed Rider AMRP mimics in all of its provisions the Rider AMRP approved in Case No. 2001-00092.[89]

In Case No. 2001-00092 the AG contended that the Rider AMRP is single-issue rate making and briefed the absence of statutory authority to engage in between rate case single-issue rate making at length. The Commission ruled against the AG repeatedly in Case No. 2001-00092 and again in each of the successor cases in which the new rates to be charged under the Rider AMRP were established.[90] Those rulings were followed by two actions that have bearing on whether a new Rider AMRP should be issued.

---

[89] Application, Schedule L-1, p. 36, Sheet 63.

[90] See, *An Adjustment of Rider AMRP of the Union Light, Heat and Power Company*, Case No. 2002-00107, 30 August 2002 Order; *An Adjustment of Rider AMRP of the Union Light, Heat and Power Company*, Case No. 2003-

First is the Commission's 15 April 2005, refusal to grant the requests of Louisville Gas & Electric Company and Kentucky Utilities for single-issue rate making in connection with proposed trackers to recover between rate cases the utilities' MISO costs not already included in existing rates.[91] In that case the Commission recognized the Supreme Court's ruling in *Kentucky Industrial Utility Customers v. Kentucky Utilities Co.*, Ky., 983 S.W.2d 493 (1998) saying:

> In discussing the rate-making procedure under KRS Chapter 278, the Supreme Court stated as follows:
>
> Prior to 1992, a utility could increase its rates only pursuant to the Fuel Adjustment Clause or as a general rate case. A general rate case pursuant to KRS 278.190 is a lengthy procedure in which a new base rate is approved only after thorough examination of all operations and costs by the PSC. In 1992, the General Assembly enacted the statute involved in this case [KRS 278.183] which allows utilities to use Kentucky coal and collect the costs of cleaning high sulfur coal. The effect is that the statute provides an alternate procedure to increasing the base rate by allowing utilities to recover the costs of environmental compliance by means of a surcharge rather than by opening a general rate case. *Id.* at 496-497.
>
> The General Assembly has similarly authorized limited alternative procedures to a general rate case for a utility to recover certain specified costs, such as: wholesale increases in water and sewage costs (KRS 278.012); the Commission's annual assessment and consultant costs (KRS 278.130); and demand-side management costs (KRS 278.285). However, no such statutory authorization exists for the recovery of MISO costs absent a general rate case.
>
> The Commission agrees in principle with the argument of LG&E and KU that, under KRS 278.030(1), we possess broad implied authority to adopt rate surcharges if they are found to be "fair, just and reasonable." However, absent specific statutory authorization, the Commission can only exercise its authority to adopt rate surcharges in the context of a general rate case.
>
> The Commission does acknowledge that certain findings in Case No[s] ... 2001-00092 regarding our rate-making authority may be overly broad when viewed in light of the Supreme Court's decision in the above-cited *KIUC v. KU* case. To the

---

00103, 25 August 2003 Order; and, *An Adjustment of Rider AMRP of the Union Light, Heat and Power Company*, Case No. 2004-00098, 24 August 2004 Order. All Orders are currently pending on appeal.

[91] See, *The Application of Louisville Gas and Electric Company for Approval of New Rate Tariffs Containing a Mechanism for the Pass-Through of Miso-Related Revenues and Costs Not Already Included in Existing Base Rate*s, Case No. 2004-00459 and *The Application of Kentucky Utilities Company for Approval of New Rate Tariffs Containing a Mechanism for the Pass-Through of Miso-Related Revenues and Costs Not Already Included in Existing Base Rates*, Case No. 2004-00460.

> extent that our prior findings are inconsistent with those of the Court, our findings must yield.[92]

In this Order, the Commission also distinguished surcharges or tariffs established within the context of a rate case from those sought outside a rate case. That distinction is without meaning within the statutory scheme established by KRS Chapter 278. Absent the statutory authority to engage in the single-issue rate making for these costs outside the general rate case, no such authority can be derived from the fact that the tariff was first brought up in a general rate case.

The second item significant to whether the request for a new Rider AMRP should be granted was the enactment this year of KRS 278.509 that provides in part,

> Notwithstanding any other provision of law to the contrary, upon application by a regulated utility, the commission may allow recovery of costs for investment in natural gas pipeline replacement programs which are not recovered in the existing rates of a regulated utility.

Under the statutory scheme presented by KRS Chapter 278, the utility may still only increase its rates pursuant to a general rate case brought under KRS 278.190 or under other specific statutory authorization. *Kentucky Industrial Utility Customers v. Kentucky Utilities Co.* at 496. KRS Chapter 278 is replete with provisions that not only recognize special treatment for some costs but also specify the availability of single-issue rate treatment for those costs outside of a general rate case.[93] By comparison to KRS 278.012 (water district has specific authority to increase rates without prior Commission action in the event of an increase of rates by the wholesale water supplier), KRS 289.130 (the Commission shall authorize a request to increase rates to recover the PSC assessment and the hearing on that application shall consider no other issue), KRS 278.183 (requires the conduct of a hearing on an application for recovery via

---

[92] Id @ 6-8.

[93] See, KRS 278.183, KRS 278.285, KRS 278.130, and 278.012.

environmental surcharge within six months of the application and specifies the matters to be considered), and KRS 278.285 (specifies that demand side management cost recovery mechanisms may be considered in a general rate case or by separate proceeding) it is clear that legislative authorization for single-issue rate making pertaining to replacement costs of mains for gas distribution companies between general rate cases is lacking under KRS 278.509.

In all of the other statutes, specific provisions authorizing consideration outside a rate case are included in the statute. In KRS 278.509 there is no like provision, the only statement the statute makes is that on application by the utility the Commission may grant recovery of costs not included in existing rates. It no more defines the circumstances under which the application is to be made and heard than does KRS 278.030, KRS 278.260 or KRS 278.180. Absent specific enabling legislation otherwise, the matter is to be heard under RKS 278.190. Consequently, the Commission, even with the newly enacted KRS 278.509 has no authority to conduct between rate case hearings and to impose between rate case single-issue rate increases. Therefore, it should refuse to approve a new Rider AMRP.

2. If the Rider AMRP is authorized, it terms must comply with the provisions of KRS 278.509. The proposed tariff does not comply.

Assuming for the sake of argument, that the Commission finds that KRS 278.509 authorizes applications to be considered between general rate cases, it must refuse the tariff proposed by Union.

KRS 278.509 provides:

> Notwithstanding any other provision of law to the contrary, upon application by a regulated utility, the commission may allow **recovery of costs for investment** in natural gas pipeline replacement programs which are not recovered in the existing rates of a regulated utility. [Emphasis added].

Like its predecessor, the newly proposed Rider AMRP provides:

> Rider AMRP will be updated annually, in order to reflect the impact on the Company's **revenue requirements of net plant additions as offset by operations and maintenance expense reductions** during the most recent twelve months ended December. [Emphasis added].

In its preceding Rider AMRP cases, Union developed net revenue requirements to recover both the cost of its investments and a return on its investments. KRS 278.509 does not provide for recovery of the return on investment. It provides only for the recovery of "costs for investment." This terminology is not found in the decisions or law previously utilized by the Commission. Prior decisions speak of both of the cost of an investment and the return on the investment.

The return on the investment is the Company's profit margin, not its cost. In recognition of this, in KRS 278.183 the legislature specifically defined the return as a cost for the purposes of surcharge recovery under that statute. Thus, when the legislature wants the return/profit to be treated as a cost, it makes specific provision for that treatment. It has not done so in KRS 278.509. The return on investment, the profit margin, is not included in KRS 278.509 and should not be allowed if a new Rider AMRP is authorized.

KRS 278.509 also makes no provision for the offset of costs for investment with decreases in maintenance and operations expense. This operates to the detriment of ratepayers and runs counter to the proposed Rider AMRP which declares that it will offset reductions in maintenance and operations against capital investment in establishing the revenue requirement. Together with added safety, this offset is described as the benefit derived by ratepayers from the AMRP program.[94] Loss of that benefit makes the Rider AMRP even less desirable.

The Commission is given discretion under KRS 278.509. It may grant an application by a utility, but it is not required to do so. It should not grant this application.

---

[94] Rebuttal Testimony, John P. Steffan, p. 3.

3. If a new Rider AMRP is established, collection of those charges from the Residential and General Services classes should be by volumetric charge or by a mixture of demand and customer charges that matches the collection of charges for like assets of the utility in base rates.

Under the Cost of Service study presented by the AG, the mains in base rates are collected 22% in the customer charge and 78% in the demand/volumetric charge for the Residential class. The variances between customers in these classes may seem small compared to the large volume transportation customers for whom Union has proposed the use of the volumetric charge as the means for the collection the AMRP charges, but the variances are, as among the customers within the Residential and General Services classes, large. When the entire Rider AMRP cost is collected under a Customer Charge, the customer who only cooks with gas and heats by some other means pays the same as the customer who heats with gas or heats and cooks with gas in the Residential class. When the Rider AMRP costs are collected with a Customer Charge for the General Service class, the farmer who uses natural gas to fuel his corn dryer in which he may well dry the crops of others as well as his own crop of corn pays the same as the farmer who just heats the stripping room or foaling stall of his barn with gas. The collection of the AMRP charges should either mimic the collection for like costs included in base rates in their division between a customer charge and a volumetric charge for the Residential and General Service classes or they should flow with the volumetric charge for all classes.

Regardless of the allocation between customer charge and demand, the AMRP cost recovery should again be a clearly designated line item if a new Rider AMRP is authorized.

4. If a new Rider AMRP is established, it should again be for a three year term. Alternatively, it should contain a sunset clause.

If a new Rider AMRP is established and follows the pattern of the first Rider AMRP so that the parties are unable to make any challenge other than to the actual cost of construction included in the rate (i.e.-unable to challenge the cost of debt, the capital structure, or the rate of return should one be included again the annual calculation of the revenue requirement), then despite the fact that a Rider has been in place for three years before, the new Rider AMRP should have a short term so that stale costs are not built into the rate established by the Rider.

If no term shorter than the end of the 10-year term of the AMRP is placed on the Rider, then the Rider should contain a sunset clause matching the end of the program. The Rider is the quid pro quo to keep Union financially sound during the AMRP period of construction. The Rider should be limited so that at the close of the term of the program, the special rate recovery offered by the Rider also ends.

Finally, at the end of ten year replacement program Union should be required to bring a case to "roll-in" to base rates the amounts collected under the Rider AMRP. This would bring closure to the program as a whole and create consistent treatment of recovery for all assets.

POLICY ISSUES: NON-MONETARY RECOMMENDATIONS

As Union's counsel put it, depreciation is "by its nature...a process of estimations."[95] The result of this process is an ever increasing and very large accumulated depreciation reserve[96] that is never subjected to a check to determine whether the salvage estimations that are built into the depreciation rates are remotely accurate. That depreciation reserves far exceed annual experienced cost of removal, the utility says, is only to be expected given the growth of the utility because the reserve is accruing the cost of removal for assets being retired today and both the capital costs and the future costs of removal of the current additions to and still-serving assets in rate base.

[95] TE Vol. II, p. 48.

[96] ULH&P's Form 10-K shows an increase in accumulated depreciation fro $27 to $30 Million between December 2003 and December 2004, representing a on year increase of $3 million over and above the cost of removal. DT Majoros, p. 23.

That assertion does not resolve the question of whether the growth in depreciation reserves is too great because it contains unrealistically high estimates of future costs of removal. Neither does it change the fact that, to date, there has been no accounting to verify that projected salvage expense reflects or matches realized salvage expense within the process of depreciation based exclusively on estimations. Heretofore, the process has been one in which utilities compare themselves to one another to be sure their estimations are in line,[97] but do not appear to track the estimations against actualities. The AG urges the Commission to adopt transparent accounting and accountability for depreciation so that there can be a check of estimation against reality.

Accurate depreciation is a benefit to both shareholders and ratepayers. The accuracy of depreciation must extend to the amounts collected as well as to the timing of the collection. Imbalances in the amount collected, as well as imbalances in the timing of payments, will skew what is designed to be a balance between the interests of the shareholders and ratepayers. It is the Commission's task to strike that balance and transparent accounting will aid in that process.

For financial purposes, SFAS 143 requires that when the utility has collected for the future cost of removal within its depreciation rates on assets for which there is no legal requirement of removal in connection with retirement of the assets, the resulting depreciation reserves are to be reported as a regulatory liability until such time as the amounts collected are spent for the purpose for which they were collected; to wit, asset removal.[98] These are reported together with excess amounts collected for removal of assets on which there is a legal obligation of removal in connection with retirement of the asset.

[97] TE Vol II, p. 48-49.
[98] DT Majoros, p. 22.

With the adoption of SFAS 143 the magnitude of the dollars prepaid by ratepayers based up estimates of future costs of removal and the relative insignificance of annual retirements became apparent. SFAS 143 has no impact on rates, it is simply enhances reporting. But that enhanced reporting has made a potential problem evident. FERC 631 also requires identification for accounting purposes of collections for future costs of removal on assets for which there is no legal obligation for removal in connection with the retirement of the asset. FERC 631a also has no impact on depreciation rates, but provides enhanced reporting. The adoption of these enhanced reporting requirements demonstrates a concern in the financial community and at FERC with not just the fact that there is depreciation, but that significant portions of depreciation are comprised of untested estimates.

In connection with those assets for which no legal obligation of removal upon retirement exists, the AG recommends that the Commission adopt enhanced reporting on a going forward basis that will allow it to watch the depreciation process of estimation, collection, and spending on costs of removal over the long term. The process will not harm the utility.[99] Only by watching over the long term will it become apparent whether estimations and realized spending are working together so that amounts estimated and collected from ratepayers reasonably match amounts expended.

If estimations/collections for future costs of removal do match spending, the enhanced reporting will have validated the results despite the process of depreciation being one of estimation upon estimation. If they do not match, then the Commission will have a better understanding of where and why the process has failed. Transparent accounting requires separation of the reporting within depreciation of capital recovery from future costs of removal.

---

[99] TE Vol. II, p. 8.

As a starting point, Mr. Majoros has prepared Exhibit__(MJM-2) that breaks the depreciation out in this fashion.

Because depreciation deals with many assets whose lives are long, the transparent reporting begun today may not bear fruit for years to come. Because the depreciation reserves are large and have been increasing by substantial amounts for each year since the transparency afforded by SFAS 143 and FERC 631 has been in place, the AG believes that transparent and enhanced reporting will ultimately demonstrate that depreciation rates have included estimated future costs of removal that exceed the actual costs experienced for the retirement/removal of the assets for which the costs were estimated. If that is the case, it will be clear that the estimations produced phantom expenses, expenses that were paid by ratepayers but never incurred by the utility. If this is the knowledge gained from the enhanced reporting, it will serve no purpose for ratepayers who have prepaid for phantom expense unless it is accompanied by some means to remedy the situation. For that reason, the AG recommends that a regulatory liability be created on a going forward basis so that if it proves true that ratepayers have shouldered a phantom expense, the utility does not keep the benefit of that windfall.

Regulatory liabilities, like regulatory assets, allow the Commission to consider during the ratemaking process financial events that occur outside the ratemaking timeframe. They are used with caution to cover significant costs that are non-recurring expenses which produce a long term benefit for customers.[100] Certainly we are speaking of a long term benefit for customers either in the establishment of the validity of the estimated costs of removal or in the establishment of the invalidity of the estimates in conjunction with a regulatory liability that will allow the Commission to act on that finding. The assets are many and the future cost of removal is

[100] See, *In the Matter of: Application of The Union Light, Heat and Power Company for Approval of Modifications to Accounting Practices to Establish Regulatory Assets and Liabilities Related to Certain MISO-Related Costs and Revenues Not Already Included in Existing Base Rates*, Case No. 2005-00096, Order of 28 July 2005.

recovered in annual increments resulting in a depreciation expense in each year. Still, the future cost of removal is but one unique non-recurring expense for the asset to which it applies. The costs are significant; the current depreciation reserve is $30 million and increasing annually by $3 million.[101]

Further, because the lives of so many assets are long, the term between rate cases is not sufficiently long to allow the Commission to observe the process and it does not retain the jurisdiction of to deal with any issues that are revealed by way of the transparent accounting absent the creation of the regulatory liability. A regulatory liability to cover the cost of removal collected until such time as it is spent on removal will allow the Commission to retain the jurisdiction to act as warranted. The utility will be accountable for amounts collected for but not spent on cost of removal only if a regulatory liability is created.[102]

The AG is not recommending a refund. Instead, he is recommending transparent reporting together with the creation of a regulatory liability that will establish a vehicle through which the Commission can grant relief if relief is warranted.

The AG also recommends that the funds in the regulatory liability be collected subject to refund to the extent not expended on cost of removal. Again, the AG is not seeking a refund, but rather establishing a means by which relief can be granted if warranted. Transparent accounting will move the process from one in which the validity of the estimates has been assumed to one in which the actual expense can be identified and examined. Collection of future costs of removal subject to refund to the extent not actually spent on removal within a regulatory liability will retain Commission jurisdiction over the funds for the long interim between collection and use so that the benefit of the funds may be directed where warranted. It will also allow the Commission

[101] DT Majoros, p. 23.
[102] SFAS 71 addresses the means by which accountability for regulatory liabilities established by a Commission are normally addressed. DT Majoros, p. 25.

continuing jurisdiction if, during the interim, events like deregulation (an event not foreseen as a real possibility even 15 years before it happened) occur that disturb the orderly process of depreciation.

NOTICE OF FILING AND CERTIFICATION OF SERVICE

I hereby give notice that I have filed the original and ten true copies of the foregoing Post Hearing Brief of the Attorney General with the Executive Director of the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601 this the 21st day of September, 2005, and certify that this same day I have served the parties by mailing a true copy, postage prepaid, to the following:

JOHN P STEFFEN
VICE PRESIDENT RATES
THE UNION LIGHT HEATAND POWER CO
139 E FOURTH ST
CINCINNATI OH 45202

ROBERT M WATT ESQ
ATTORNEY AT LAW
STOLL KEENON AND PARK LLP
300 W VINE ST STE 2100
LEXINGTON KY 40507 1801

JOHN J FINNIGAN JR ESQ
SENIOR COUNSEL
THE UNION LIGHT HEAT & POWER CO
139 E FOURTH STREET
CINCINNATI OH 45202

KATE E MORIARTY
THE UNION LIGHT HEAT & POWER DO
139 E FOURTH ST
CINCINNATI OH 45202