MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

SURREBUTTAL TESTIMONY

OF RONALD L. BIBLE

Schedule 7 through Schedule 11

CASE NO. EC-2002-1

UNION ELECTRIC COMPANY
d/b/a AMERENUE

Jefferson City, Missouri
June 2002

THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

Before Commissioners: John Wine, Chair
Cynthia L. Claus
Brian J. Moline

In the Matter of the Application of Western Resources, Inc. for Approval To Make Certain Changes in its Charges for Electric Service. In the Matter of the Application of Kansas Gas and Electric Company for Approval To Make Certain Changes in its Charges for Electric Service.	)	Docket No. 01-WSRE-436-RTS

ORDER ON RATE APPLICATIONS

The above matter comes before the State Corporation Commission of the State of Kansas (Commission) for consideration. Having reviewed its files and being fully advised of all matters of record, the Commission finds:

BACKGROUND

1. On November 27, 2000, Western Resources, Inc. (WRI) filed an Application seeking an increase in its annual revenues of $92,581,768. WRI provides electric service in Kansas under the name KPL. Also on November 27, 2000, Kansas Gas and Electric Company (KGE), a wholly owned subsidiary of WRI, filed an Application seeking an increase in its annual revenues of $57,924,438. These rate filings were consolidated for consideration and hearing. The combined requested rate increase is $150,506,206. When WRI and KGE are referred to jointly, they will be identified as the "Applicants."

2. WRI and KGE are electric public utilities as defined in K.S.A. 1999 Supp. 66-104. The Commission has jurisdiction of the utilities and rate requests pursuant to K.S.A. 66-101, *et seq.*

3. On December 21, 2000, in its Pre-Hearing Conference Order, the Commission scheduled an evidentiary hearing on the requested rate increases. Notice of the proposed rate

Schedule 7

increases, public hearings, and the technical evidentiary hearing was also provided through inserts in customer bills and publication in newspapers of general circulation in the utilities' service territories. Public hearings on the rate applications were held in Wichita, Kansas on April 11, 2001; in Salina, Kansas on April 17, 2001; in Topeka, Kansas on April 19, 2001; and in Pittsburg, Kansas on April 26, 2001. No objections to notice have been made and the Commission finds that notice was proper.

4. The evidentiary hearing was held at the Commission's offices in Topeka, Kansas, from May 17, 2001 through June 4, 2001. Appearances of counsel were as follows: Martin J. Bregman, Michael Lennen, James M. Fischer and Donald D. Barry on behalf of the Applicants; Susan B. Cunningham, W. Thomas Stratton, Jr., and Glenda L. Cafer on behalf of Commission Staff and the public generally; Walker Hendrix and Niki Christopher on behalf of the Citizens' Utility Ratepayer Board (CURB); James P. Zakoura on behalf of Kansas Industrial Consumers (KIC); Timothy E. McKee, Gregg D. Ottinger and Gary E. Rebenstorf on behalf of the City of Wichita (Wichita); Sarah J. Loquist and Thomas R. Powell on behalf of Unified School District No. 259 (USD 259); Kirk T. May and Matthew T. Geiger on behalf of Goodyear Tire & Rubber Company (Goodyear); John C. Frieden and Kevin M. Fowler on behalf of the City of Topeka (Topeka); James G. Flaherty and Daniel Covington on behalf of the Empire District Electric Company (Empire); Brock R. McPherson on behalf of Midwest Energy, Inc.; Larry M. Cowger on behalf of Kansas Gas Service Company; and C. Edward Peterson, Stuart Conrad and Jeremiah Finnegan on behalf of Kansas Municipal Energy Agency.

5. Subsequent to the hearing, briefs on the issues were filed by the Applicants, Staff, CURB, Wichita, KIC, Goodyear, Topeka, and USD 259. Reply briefs were filed by the Applicants, Staff, Wichita, KIC, USD 259 and Topeka.

6. At the hearing, the Commission took administrative notice of the following records and documents pursuant to K.A.R. 82-1-230(i):

a. from Docket No. 99-WSRE-381-EGF [Gordon Evans siting permit], the February 15, 1999 testimony of Larry Holloway; the December 2, 1998 Joint Application; and the March 30, 1999 Order. (Transcript, 15-19, 892-93.)

b. from Docket Nos. 193,306-U and 193,307-U [KGE and WRI depreciation / rate cases], the October 14, 1996 testimony and exhibits of Mark F. Doljac; the direct testimony of Jerry D. Courington and Tom Bozeman; the October 22, 1996 Motion to Approve Amended Settlement Agreement; the October 29, 1996 Order; the January 15, 1997 Order; the Transcript, pp. 615-18; the October 17, 1996 testimony of James M. Proctor, pp. 4-12 and 16-20. (Transcript, 1374-75; 1871-72; 1939.)

c. the November 15, 1991 Order in Docket Nos. 172,745-U and 174,155-U [approving the merger of KPL and KGE.] (Transcript, 1893.)

d. the September 17, 1987 Order and Certificate in Docket No. 156,521-U [LaCygne sale/leaseback transaction.] (Transcript, 1981-83.)

e. the November 9, 2000 Initial Decision by the Administrative Law Judge in Federal Energy Regulatory Commission (FERC) Docket No. EL99-90-002 [City of Wichita v. Western Resources, Inc.] (Transcript, 2034-35.) This is also Exhibit HEO-1 to the rebuttal testimony of H. Edwin Overcast.

f. from Docket No. 97-KCPE-661-RTS [review of Kansas City Power & Light Company's revenue requirement], the January 6, 1998 Order No. 6 Adopting Amended Settlement Agreement; and the November 17, 1997 Motion to Modify Suggested Procedural Schedule. (Transcript, 2119-20.)

g. the February 11, 2000 Order Issuing Certificate in FERC Docket No. CP99-576-000 [Williams Gas Pipelines Central, Inc.] (Transcript, 2148-49.)

h. from Docket No. 97-WSRG-486-MER [WRI, ONEOK and WAI merger], the March 28, 1997 Motion to Amend Joint Application; and the June 3, 1997 Petition for Reconsideration. (Transcript, 2589.)

Organization of this Order

7. The issues in this Order are organized into several general areas. The discussion of each area begins on the page listed. An alphabetical index of issues is also attached to the Order.

PRELIMINARY MATTERS

Restructuring Issues

8. As one Commissioner noted during the hearing, the plans of the Applicants to restructure their corporate organization have been "lurking in the background" throughout this rate case. (Transcript, 2411.) Several parties addressed the restructuring proposals at length in testimony and at the hearing. The Applicants have emphasized that restructuring issues should not be part of a proceeding to determine cost of service and that the concerns of the parties will be able to be considered by the Commission in future proceedings (such as a merger filing). They state that the Commission should focus on regulatory matters and not on management decisions. Conversely, Staff and Intervenors posit, in varying degrees, that the Commission cannot ignore the evidence in the record of the Applicants' restructuring plans and the effects on the financial health of the utility and on ratepayers.

9. The Commission has a statutory duty to monitor the financial condition of electric utilities and the ability of the utilities to provide sufficient and efficient electric service to Kansas ratepayers. K.S.A. 66-101, *et seq.* Parties challenging the Applicants' restructuring plans have pointed to the detriment to electric customers that would result from an electric utility with an actual capital structure that is primarily composed of debt. This situation, if it were to occur, would negatively affect regulated electric operations and would undeniably require Commission inquiry and action. However, it appears to the Commission that this is not a direct concern for ratemaking purposes unless and until the Applicants separate their regulated and non-regulated components and expose the standalone electric utility to imbalanced debt/equity ratios. (Transcript, 1987.)

10. The Commission will not presuppose in this proceeding what will happen with the Applicants' corporate structure and what the financial condition of the electric utility will be in the future. The Commission will base its rate ruling on the utility structure as it exists today. However, the Commission does order that the rates set in this case be interim and subject to refund until it is determined what will occur with the electric utility and the Commission is assured that there will not be an electric utility in financial distress. The Commission considers this to be the only prudent course of action.

11. Because the evidence indicates that separating the regulated and non-regulated business operations of the Applicants, together with other announced elements of the restructuring plans, would result in an electric utility with an actual capital structure that is heavily debt-laden (Transcript, 2976), Staff has proposed an interest synchronization adjustment. (Proctor direct, 11-12, 47-50; Proctor cross, 2-7; Proctor surrebuttal, 4-10; Transcript, 1863-67, 1947, 1987-95.) KIC and USD 259 also support Staff's adjustment. This interest synchronization adjustment would not be applied to the interim rates set in this Order, but would be applied if management actions result in

a standalone electric utility with an excessive level of debt. With a hypothetical ratemaking capital structure that contains more equity than the Applicants actually have, the Applicants will be recovering taxes in rates that they do not pay in reality. Staff maintains that its interest synchronization adjustment is necessary to prevent the Applicants from receiving excessive and unintended returns relative to an actual all-debt capital structure. The Applicants assert that Staff's interest synchronization adjustment is improper and would prevent the Applicants from recovering the return authorized. (Martin rebuttal, 5-6; McKnight rebuttal, 4-14; McKnight reply, 2-4; Transcript, 3035-36.)

12. The purpose of an interest synchronization adjustment is to synchronize the portion of the rate base that is supported by debt with the interest expense deductions that determine current income tax expense for ratemaking purposes. When there is a hypothetical capital structure, the capital structure used to set rates is different from the actual capital structure that supports the rate base. (Proctor cross, 3-4.) The difference between the positions of the parties is that the Applicants use the hypothetical capital structure weighted-average cost of debt to calculate interest expense, and Staff uses the actual utility capital structure weighted-average cost of debt. (Proctor direct, 48.)

13. The Commission has considered the Applicants' arguments and does not find them to be persuasive. In this case, a hypothetical capital structure is necessary due to the Applicants' debt/equity imbalance. The Commission is adopting a hypothetical capital structure which, for ratemaking purposes, treats some debt as if it were equity. The allowed return on equity is greater than the allowed return on debt. These circumstances provide the opportunity for the Applicants to benefit in two ways. First, the greater amount of equity in the hypothetical capital structure provides the Applicants with a greater recovery than they would receive if rates were based on the actual utility capital structure. Secondly, at the same time that the Applicants are receiving an increased

return through the artificially high level of equity in the capital structure, they also receive a tax benefit because the interest deduction related to the hypothetical capital structure is less than the actual interest deduction that they take when income taxes are paid. (Transcript, 1863-67.) Staff's adjustment recognizes this fact and uses the actual capital structure of the standalone utility, with the high debt level, to determine the interest expense that is incorporated in the Applicants' income tax calculation. (Transcript, 1947.) Staff's adjustment recognizes that the Applicants' actual interest expense is greater than what would be consistent with the hypothetical capital structure. This means that, absent the adjustment, the Applicants would collect from ratepayers current income tax expense that they would not actually pay. (Transcript, 1995.) Without Staff's adjustment, the Applicants would receive a greater tax benefit than is contemplated in the regulatory capital structure, and would recover a higher return than the one authorized by the Commission. Staff's adjustment would ensure that customers do not pay rates that provide for an overall recovery in excess of what the Commission has determined to be just and reasonable. Staff's adjustment, calculated with the capital structure that the electric utility would have as a standalone entity today, would result in an additional decrease of $26,065,153 to KGE's revenue requirement and a decrease of $23,133,108 to WRI's revenue requirement.

14. The Applicants argue that this particular type of interest synchronization is novel. However, the testimony indicates that a utility with an actual all-debt capital structure is also novel and unique, and presents unusual and challenging regulatory problems. The Commission finds that the theory behind Staff's adjustment is sound, and that if a utility with an inappropriately high debt level is created, it will be a result of the actions and decisions of the Applicants. If such a standalone utility comes into existence, Staff's interest synchronization adjustment, using the actual utility capital structure, will be applied to determine permanent rates. If the Applicants are correct in their

speculation, and a perilous debt/equity ratio does not materialize or materializes only for an insignificant period of time, then this adjustment will not be applied and the Applicants may move to have the interim rates made permanent.

Staff Wholesale/Retail Allocation

15. Staff maintains that the Applicants are able to manipulate their wholesale contracts to the detriment of retail ratepayers by having KPL enter into the wholesale contracts instead of KGE. Staff argues that because the system is jointly operated and dispatched, all wholesale sales are supported by the generation resources of both KPL and KGE, and the selection of which particular utility is a party to a contract is arbitrary. Because KPL's historic overall costs are lower than KGE's, the wholesale customers benefit relative to retail customers. The Applicants allocate more of the expensive KGE generation to retail customers, who pay a higher rate based on these higher costs. Staff argues that this manipulation is unfair to retail customers and can be reversed by adjusting the allocations between wholesale and retail customers that have been made by the Applicants and considering the utilities on a combined basis. (Holloway direct, 7-9; Proctor direct, 71-75; Transcript, 2027-31.)

16. The Applicants claim that this adjustment would not respect wholesale contractual rates that have been approved by the Federal Energy Regulatory Commission (FERC) and would deprive the Applicants of a reasonable opportunity to recover their prudent costs. The Applicants emphasize that the two utilities are separate entities with separate histories, generation assets and load obligations. (Overcast rebuttal, 3-14 ; Rohlfs rebuttal, 2-8; Transcript, 2733-37, 2748.)

17. It appears to the Commission that the Applicants may be using the different costs of KGE and KPL to favor wholesale customers over retail customers and that the manner in which the contracts are designated is questionable. The actual power for wholesale customers (other than those

with participation agreements) could come from either KGE or KPL facilities. The Applicants raise legitimate concerns regarding the effect of Staff's adjustment on their ability to recover legitimate costs and on the regulatory dilemma that is created between Staff's adjustment and the contractual provisions approved by FERC. The Commission believes that this area should be scrutinized further and strongly encourages the Applicants to change the way that these contracts are handled so that this inequity does not continue. At this time, the Commission is not accepting Staff's adjustment, but the adjustment may be raised again at any appropriate time.

Separate Revenue Requirements for KGE and KPL

18. Wichita and Staff have presented evidence that combining revenue requirements would be one way of addressing the historic differential between KGE and KPL retail rates. The rate differential must be viewed in light of the historical record. No party in the 1991 KGE and KPL merger proceeding, including Staff and Wichita, advocated combining revenue requirements at the time. Mergers should benefit the ratepayers. KGE's ratepayers benefitted measurably in the 1991 merger since scheduled rate increases were cancelled. Subsequent rate reductions were also channeled primarily to KGE. KPL ratepayers also benefitted from the 1991 merger, but not as directly or dramatically as KGE. The Commission is committed to reducing the rate differential, and has previously taken steps to do so. (January 15, 1997 Order, Docket Nos. 193,306-U and 193,307-U.) As will become evident later in this Order, the adjustments in this case make significant progress towards addressing the rate differential.

Test Year

19. These Applications were filed with a test year ending September 30, 2000, and with the request for inclusion of certain costs outside of the test year relating to new generation facilities. Several parties contend that the Applicants have selectively included only expenses which occur

after the test year, and have ignored revenues and offsetting adjustments after the test year which are known and measurable. The applicable test year for this proceeding ends on September 30, 2000. The Commission also has the discretion to include post-test year changes which are known and measurable. *Gas Service Co. v. Kansas Corporation Commission*, 4 Kan.App.2d 623, 636-36, 609 P.2d 1157, *rev. denied* 228 Kan. 806 (1980). The Commission will consider proposed adjustments based on changes after the test year which would either increase or decrease the revenue requirement and will rule on them individually in accordance with the known and measurable standard.

SETTLED ISSUES

20. On the second day of the hearing, the parties informed the Commission that they had reached settlements concerning six issues. The parties accepted the Applicants' adjustments for Wolf Creek 18-month fuel stock, economic development, actual billed revenues, and plant completed - not classified. The parties also agreed to Staff's weather normalization adjustment and that quality of service standards should be considered in a generic manner in a docket or through the adoption of administrative regulations. In connection with quality of service, the Applicants agreed to retain six years of actual historic reliability data on a going forward basis. (Transcript, 242-43; Doljac direct, 51-52.) <u>The Commission directs Staff to initiate its review of quality of service standards on or before November 1, 2001</u>.

21. The Commission finds that the settled positions on these matters are reasonable. The Commission accepts the settlements and adopts the amounts and adjustments as part of this Order.

DEPRECIATION

22. Two comprehensive depreciation studies were presented at the hearing - Aikman on behalf of the Applicants, and Majoros on behalf of CURB, KIC, Wichita, Goodyear and USD 259. The Applicants request an increase from current depreciation rates. (Aikman direct, Appendix E.)

23. Staff notes that Aikman uses the remaining life technique for his depreciation analysis, instead of the whole life method currently used by KPL and KGE. Staff has no objection to the remaining life approach so long as an updated depreciation study is filed every five years. Staff questions Aikman's life estimates for the Jeffrey, LaCygne, Lawrence and Wolf Creek facilities. Staff also recommends that transmission and distribution rates be combined and that Staff's revised net salvage site values be recognized. (Holloway direct, 3-4, 9-28; Holloway cross, 5-9; Holloway surrebuttal, 10-11; Transcript, 2086-2178, 2186-2204.)

24. The Majoros study incorporates longer remaining lives for the LaCygne, Jeffrey, Lawrence, Gordon Evans, State Line and Wolf Creek units, but accepts Aikman's net salvage values. (Majoros direct, 4, 10-21, Exhibits MJM 1-12; Transcript, 2209-2227.) Topeka asserts that the lives for the new Gordon Evans combustion turbines should be 35 years, instead of the 25 years used by Aikman. (Bodmer direct, 6-7.)

25. The Applicants acknowledge that depreciation studies require the use of judgment and include projections for the future. The development of depreciation accrual rates is a subjective process to a great extent. (Transcript, 1312-1314.) Decisions about life spans are the most important factor in depreciation analysis, and they also involve judgment. (Transcript, 1388.)

26. The Commission finds the Majoros depreciation study and recommendations to be the more persuasive and adopts them. The Majoros study is supported by a detailed nationwide actuarial study of steam units, by personal inspections of several of the Applicants' plants, and by a life extension study prepared by the Applicants. (Majoros direct, 3-4, 10-24; Transcript, 2211, 2221.) The Applicants argue that the extended lives used by Majoros are not possible without interim capital additions, and that it would be unfair to extend the lives without recognizing the additional expenditures. (Aikman rebuttal, 2-5; Aikman reply, 3-5.) However, it is undisputed that

new expenditures are generally not recognized or included in depreciation calculations until they occur. (Aikman direct, 16; Transcript, 1409-10, 2086, 2130; KIC Trial Brief, 23-24.)

27. The Applicants do not object to Staff's proposal to combine the distribution and transmission account depreciation accrual rates (Holloway direct, 12-14; Applicant's Initial Brief, 55.) The Commission finds that this is appropriate.

28. The Commission also accepts Staff's recommendation that updated depreciation studies be prepared and filed with the Commission every five years. The Applicants did not oppose this, and the Commission finds that it will keep depreciation adjustments reasonably consistent with current information.

29. In adopting the Majoros study, the Commission is assuming that the Wolf Creek nuclear plant will request and obtain a 20-year license extension from the Nuclear Regulatory Commission (NRC). Because Wolf Creek cannot apply for a license extension until 2005, the Applicants argue that it is premature to increase the useful life of Wolf Creek. (Aikman rebuttal, 9.)

30. Staff asserts that the generating capacity from Wolf Creek will be needed well into the future. Given this fact, and the reliability and low operating costs of Wolf Creek, Staff suggests that it would be imprudent for the Applicants not to apply for and receive a 20-year life extension from the NRC. (Holloway direct, 16.) Staff originally recommended a 10-year life extension for depreciation purposes, but after reviewing the Majoros study, stated that a 20-year life extension would be reasonable. (Holloway direct, 18-19; Holloway cross, 8-9; Transcript, 2187-88.)

31. The Commission must use its best judgment in making the determination about the extension of the Wolf Creek operating license. It is undisputed that Wolf Creek is one of the newest nuclear power plants in the country, that it has modern equipment, and is operated in a good and efficient manner. Wolf Creek is also one of the better built and designed nuclear power plants.

(Transcript, 1423, 2109, 2189.) Majoros visited the NRC to investigate the status of operating license extensions (Majoros direct, 3), and Staff's witness is familiar with the Wolf Creek facility (Transcript, 2186.) However, Aikman did not discuss a possible extension with anyone at Wolf Creek or at the NRC. (Transcript, 1384-86.) Aikman informed the Commission that he would not consider anything short of an actual renewal to be a sufficient basis to extend the Wolf Creek life. (Transcript, 1385.) The Commission finds that Aikman's standard that the license actually be renewed before the plant's depreciation life can be extended to be unreasonable. Nuclear power plant license extensions are widely predicted now, and the clear trend has been to grant license extensions. (Transcript, 1369-72, 2188-90.) The information known about Wolf Creek strongly supports the conclusion that the Wolf Creek license will be extended for an additional 20 years by the NRC. Setting depreciation rates on that assumption is reasonable. There is no way to know with absolute certainty what will happen in the future with any plant. The depreciation findings are based on the best information available today. The five-year update that the Commission has ordered will provide additional opportunities to review the status of Wolf Creek and to make any adjustments that appear necessary in the future. (Transcript, 2132.)

32. Staff has acknowledged that its net salvage site value adjustment presents a nontraditional approach for valuing generation sites. The Commission is intrigued by Staff's theory, but is not adopting it at this time.

33. These findings result in changes to depreciation expenses and related deferred income taxes. The adjustment to net operating income is an increase of $16,170,045 for KGE, and an increase of $8,415,675 for WRI.

Capital Structure Issues

Capital Structure

34. The parties agree that the apparent capital structure of the standalone electric utility is not generally an appropriate one to use for ratemaking purposes, and that the preferred approach would be to determine a hypothetical capital structure. (Cicchetti rebuttal, 23, 29-30; Cicchetti reply, 2-3; Proctor direct, 17-19, 32-33, 46-47; Hill direct, 13-16; Dunn direct, 41-44, 51.) Four hypothetical capital structures have been recommended to the Commission.

35. The Applicants propose a capital structure of 50% long-term debt and 50% common equity. The Applicants state that the Commission should use a hypothetical capital structure that reflects a reasonable debt to equity relationship and that this proposal is an acceptable target which KGE and WRI should move towards. They suggest that this hypothetical capital structure would encourage the Applicants to return to an appropriate capital structure. (Cicchetti direct, 7-10; Cicchetti rebuttal, 29-30; Cicchetti reply, 2-3.) CURB opposes the Applicants' capital structure and maintains that it contains too much equity capital. (Hill direct, 11.) Staff argues that the Applicants' proposal is arbitrary and is not based on facts regarding the electric utility's financial statements or operations. (Proctor direct, 20.) KIC and Goodyear state that Applicants' hypothetical structure is not appropriate and is not supported by any work papers. (Dunn direct, 45.)

36. Staff's recommended capital structure is 51.62% long-term debt; 44.14% common equity; 0.90% preferred stock; and 3.34% accumulated deferred investment tax credits. Staff states that this capital structure represents the funds that have been used to finance the electric utility and the effect of cash flow generated by the profitable utility business. Staff's capital structure is based on an extensive cash-flow analysis. (Proctor direct, 6-13, 17-20, 28-30, Exhs. JMP-1, JMP-4.) The Applicants have acknowledged that Staff's hypothetical capital structure is not unreasonable. (Brief,

14.) USD 259 and KIC have also indicated that Staff's proposal would be appropriate. (USD 259 Brief, 31; USD 259 Reply Brief, 9,15; KIC Brief, 17-18.)

37. CURB recommends that the Commission use the consolidated capital structure of the parent company, WRI. This is 53.97% long-term debt; 39.07% common equity, 0.50% preferred stock, 4.39% preferred securities, 1.85% accumulated deferred investment tax credits, and 0.24% customer deposits. (Hill direct, 15-17.) The Applicants are opposed to this option, and KIC does not recommend that it be adopted. (Applicants' Brief, 15-16; KIC Brief, 17-18.) USD 259 would support CURB's hypothetical capital structure. (USD 259 Brief, 31; USD 259 Reply Brief, 9,15.)

38. KIC and Goodyear recommend using the combined equity ratio that would exist after the merger of the electric utility business with Public Service Company of New Mexico (PNM), and state that this is 13.97% common equity. (Dunn direct, 2-6, 51.) The Applicants contend that this proposal is highly speculative and that it is not known what capital structure the utility would have after a merger with PNM. (Cicchetti rebuttal, 117.) Staff also argues that this capital structure is speculative, and emphasizes that a post-merger utility would have additional equity related to goodwill recorded in the transaction for the premium paid above book value. (Gatewood cross, 3; Transcript, 2318-20.)

39. The Commission finds that Staff's recommended capital structure is the most reasonable and valid. Staff's capital structure is directly related to the actual condition and operations of the utility and is based on a detailed and thorough cash-flow analysis. The Commission adopts Staff's proposed capital structure.

Cost of Long-Term Debt

40. The Applicants originally requested an embedded cost of debt of 7.89% and stated that this was typical for other electric utilities. (Cicchetti direct, 26.) Both Staff and CURB argued

that a $600 million term loan with an interest rate of 10.45% should not be included in the cost of debt. CURB removed the term loan from its calculation of the embedded cost of debt, while Staff stated that the Commission should adjust the interest rate of the term loan to 7.00% if that debt is included in the capital structure. CURB proposed an embedded cost of long-term debt of 7.0589%, and Staff's proposed cost of debt was 7.14%. (Hill direct, 16-17, revised Exh. SGH-1, Sch. 2, p.5; Gatewood direct, 33-37.)

41. The $600 million term loan is in the record as Applicants' Exhibit 1. As discussed at the hearing, this loan carries a variable interest rate. In their Brief, the Applicants note that the applicable interest rate has fallen significantly and that their current embedded cost of debt is 7.5062%. (Brief, 24.) Given this fact, the Commission has concluded that the Applicants' revised embedded cost of debt is reasonable and accepts the rate of 7.5062%.

Return on Equity

42. The Applicants, Staff and CURB all recognize that the allowed return on equity (ROE) should be sufficient to assure confidence in the financial soundness of the utility, to permit the utility to attract the capital necessary to carry out its duties of providing service and meeting customer needs, and to provide a return comparable to returns which investors would expect from other investments with the same degree of risk. (Cicchetti rebuttal, 49, 52; Gatewood direct, 4-6; Hill direct, 4; Applicants' Brief, 11-12.) The Applicants' recommended ROE is 12.75%, while Staff and CURB have proposed a ROE of 10.50%.

43. To determine an appropriate ROE, the Applicants rely on a discounted cash flow (DCF) analysis, and use the risk premium method as a check on the reasonableness of the DCF analysis. (Cicchetti direct, 4, 10-23.) The Applicants also contend that an ROE higher than what is indicated by these analyses is justified by four additional risks faced by the Applicants. These

additional risks are increasing competition in the electric industry, having nuclear generation, possible fuel price increases, and the threat of Wichita municipalization. (Cicchetti direct, 28-38; Cicchetti rebuttal, 88-89; Cassidy reply, 2-3; Transcript, 3094-95.)

44. CURB and Staff question the Applicants' DCF analysis by pointing out that many of the companies in the proxy group are not primarily electric utility companies and are subject to higher risks than regulated electric utilities. (Hill direct, 44-45; Gatewood direct, 22-25.) They also raise numerous other concerns related to the Applicants' suggested ROE. (Hill direct, 43-52; Hill surrebuttal, 15-24; Gatewood direct, 21-29.)

45. Staff's recommended ROE is the average of two DCF analyses and one capital asset pricing model (CAPM). Staff's DCF proxy group consists of seven electric utility companies with at least 50% of revenues from the sale of electricity. Other criteria include having generation, transmission and distribution assets, no recent dividend cuts, positive earnings and growth forecasts, and a strong financial strength rating. Staff states that it focused on the cost of equity capital for electric utility companies that were similar to the Applicants' utility operations, and that the Applicants' utility business is much healthier financially than the overall WRI corporate entity which includes riskier non-regulated activities. (Gatewood direct, 5-21, 28-29.) Staff emphasizes that it is necessary to look at the current state of the capital markets and that comparisons of ROEs that were authorized at different times are not valid. (Transcript, 2326-2337, 2356-57.) The Applicants are critical of many aspects of Staff's analysis. (Cassidy rebuttal, 2-11; Cicchetti rebuttal, 49-90.)

46. CURB maintains that current capital costs are relatively low. CURB used a DCF model to estimate the cost of common equity capital. CURB also looked at results from a CAPM model, a modified earnings price-ratio analysis (MEPR) and a market to book analysis. For its DCF analysis, CURB selected a sample group of 11 electric companies with revenues primarily from

electric operations, bond ratings of single-A or below, and which owned generation as well as transmission and distribution operations. (Hill direct, 5-10, 17-37, 42-43.) CURB's ROE estimate was in a range of 10.00% to 10.50%. After considering differences in financial risk, CURB concluded that a 10.50% ROE was reasonable. (Hill direct, 37-43.) The Applicants have numerous disagreements with CURB's ROE recommendation. (Cicchetti rebuttal, 90-114; Cassidy rebuttal, 12-16; Cassidy reply, 1-4.)

47. The Applicants state that no formula can compute an ROE perfectly and that judgment is always a part of a rate of return analysis. (Cassidy rebuttal, 11.) Staff has asserted that different ROE methods capture different aspects of the capital markets. (Transcript, 2338.) One of the Applicants' witnesses has also said that picking a proxy group is more of an art than a science. (Cicchetti rebuttal, 87.) The Commission clearly has discretion in its ROE findings and must evaluate the reasonableness of the various options presented.

48. The Commission first notes that its obligation is to determine the cost of equity that is applicable to the electric utility operations of the Applicants. (Hill direct, 45; Transcript, 2368.) The Applicants also indicate that the ROE should be based upon the standalone value of the electricity business and physical assets. (Cicchetti rebuttal, 23.) However, the DCF approach used by the Applicants was not consistent with this principle. Both Staff and CURB emphasize that the Applicants' proxy companies are not primarily electric utilities. (Hill direct, 44-45; Gatewood direct, 22-25.) The Commission finds this to be a fundamental flaw in the Applicants' ROE analysis. The reliance on companies which are subject to greater risks than regulated electric utilities leads to the Applicants requesting an ROE that is higher than warranted. The Commission finds that the DCF analyses of Staff and CURB are more reasonable and appropriate. While the Applicants have raised questions about the ROE calculations of Staff and CURB, the Commission accepts the

premise that no ROE analysis is perfect and the criticisms do not invalidate the recommendations of Staff and CURB.

49. The Commission has considered the four additional risk factors submitted by the Applicants and finds that none are unique risks which warrant an increased ROE. The changing electric industry and volatile fuel prices are factors that affect all electric utilities. Staff and CURB accounted for these risks by choosing proxy companies that were primarily electric utilities. This general risk was captured by the proxy groups and is not an additional risk to the Applicants that requires a special adjustment. Similarly, both Staff and CURB included companies with nuclear generation in their proxy groups, and this is not a unique risk factor affecting the Applicants. (Gatewood direct, 7, 31-33; Hill surrebuttal, 18-19; Transcript, 2350-51.) The last suggested risk factor is the concern that Wichita might municipalize its electric service. Although it is reasonable to expect that Wichita will continue to pursue this option, it is uncertain how long the process might take or what the end result will be. The Commission agrees with Staff that this is too uncertain a factor to serve as a basis for an explicit ROE adjustment. (Gatewood direct, 33.) The Commission also finds the argument persuasive that other electric utilities face serious litigation matters, including potential municipalization. (Transcript, 2359.)

50. The Commission will adopt the basic ROE analysis offered by Staff. The DCF and CAPM models used by Staff have been accepted by this Commission in the past. The Commission has considered the parties' objections and qualifications to the CAPM method. The Applicants question the value of CAPM and argue that the Commission should disregard it entirely. CURB believes that it can be a less reliable analysis than DCF, but that it is a useful description of the capital markets, has not been discredited, and is a fundamental finance teaching tool. (Hill direct, 26; Hill surrebuttal, 22; Cicchetti direct, 22-23; Cassidy rebuttal, 3-5, 12.) The Commission finds

that the CAPM analysis has not been discredited and that it may provide useful information. However, in this case, the Commission will modify Staff's ROE by considering only the DCF models. Giving these two analyses equal weighting provides a revised Staff ROE of 11.02%. The Commission adopts 11.02% as a fair and reasonable ROE which meets the standards stated in Paragraph 42.

Rate of Return

51. Using the capital structure, cost of long-term debt and ROE adopted above, the approved rate of return for the Applicants is 9.0836%. The capital structure calculations are attached to this Order.

NEW GENERATION CAPACITY

52. The Applicants state that they have added approximately 514 megawatts of new generation capacity to serve KPL retail customers. This new generating capacity consists of three combustion turbine peaking units at the Gordon Evans site in Kansas, and a Purchase Power Agreement (PPA) under which WRI would purchase 200 megawatts of intermediate combined cycle capacity from Westar Generating, Inc., a wholly-owned subsidiary of WRI. The capacity is from the State Line facility in Missouri which is owned 40% by Westar Generating and 60% by Empire. (Grennan direct, 3-9; Holloway surrebuttal, Exh. LWH-S4 .) The Applicants request rate base inclusion of the costs of the Gordon Evans units, and propose that the PPA payment be an adjustment to operating expenses.

Gordon Evans

53. Two of the Gordon Evans units went into commercial service in June 2000. (Grennan direct, 4-5; Transcript, 1005.) The third Gordon Evans unit entered commercial service on June 12, 2001. (Applicants' Brief, 3.) The first two units, costing approximately $32 million each, are

included in the test year filing. The Applicants request an adjustment to recover the cost of the third unit, $61,330,718. (Grennan direct, 6; Application, Vol. I, Schedule 4-D, p. 2.)

54. Staff maintains that the three units are needed and recommends inclusion of the full Gordon Evans costs in rate base. (Holloway direct, 36-38; Transcript, 2049, 2071-72.) Topeka questions the prudence and timing of these plant investments, but states that Gordon Evans costs could be placed in rate base if adjustments are made in areas such as additional off-system sales. (Bodmer direct, 4-10, 20-22, 30-34, Schedule EBC-1; Pflaum direct, 3-4,17-13; Transcript, 2691.) CURB proposes adjustments relating to customer annualization and additional wholesale and competitive sales. (Crane direct, 38-43, Schedule 10-KPL, Schedule 11-KPL.)

55. Staff has recognized the importance of not discouraging utility plant investment when there could be a generation capacity shortage in Kansas in the near future. (Holloway direct, 37-38; Transcript, 2049.) It is clear to the Commission that these units are needed and that the costs are not unreasonable. The evidence also indicates that the units are needed to provide service to the KPL service area. The Commission finds that it is appropriate to include Gordon Evans costs in rate base. The Commission does not accept the Topeka adjustment for dual fuel capability. (Bodmer direct, 32-35.) Other requested adjustments will be discussed below.

<u>State Line Purchase Power Agreement</u>

56. The State Line PPA is more controversial. The PPA has an initial term of seven years, with an option for WRI to extend the agreement for another five years. The PPA provides for a levelized rate for the first 7 years. The Applicants state that this arrangement benefits ratepayers because it maintains flexibility for the utility and the cost is less than if the plant were in rate base. They also emphasize that the rate charged under the PPA will be set by FERC on a cost basis. The State Line plant went into commercial service on June 22, 2001. (Harrison direct, 4-5; Harrison

rebuttal, 2-10; Transcript, 795-96, 1195-97, 1206-16; Applicants' July 2, 2001 letter.)

57. Staff, CURB, KIC, Topeka, Goodyear and USD 259 have concerns about the PPA. They question the costs under the PPA, why this arrangement is used instead of having the electric utility own its own generation, and what will happen after 7 or 12 years. Parties claim that the utility should be required to take ownership of the State Line interest and that there should be offsetting adjustments for additional sales and customers, and for reduced fuel costs. KIC also argues that WRI acted imprudently in 1995 when it agreed to sell 162 megawatts of Jeffrey participation power to Empire, and that the higher costs of the State Line plant should be assigned to wholesale operations and the lower Jeffrey costs assigned to retail customers. (Dittmer direct, 33-44.)

58. Ths PPA was the subject of a significant amount of testimony and was discussed extensively at the hearing by the parties and the Commissioners. (See generally the cross-examination of Grennan and Harrison, Transcript, Volumes 4 and 5.) The evidence is conflicting as to whether ratepayers are disadvantaged over time by leased generation as opposed to owned generation, and as to whether the 1995 sale to Empire of owned generation capacity artificially created the need to participate in the State Line PPA. Intervenors and Staff urge the Commission to direct jurisdictional utilities to own rather than lease capacity.

59. The Commission accepts the explanation of the 1995 Empire sale provided by the Applicants (Fitzpatrick rebuttal) and finds no basis to declare that the sale was imprudent. After much deliberation, the Commission concludes that it cannot find with certainty that the decision to enter into the PPA or the terms of the PPA are unreasonable. The Commission therefore adopts the Applicants' proposed treatment of the PPA.

60. The PPA gives the utility flexibility, which may be a benefit with changes occurring in the industry. The Commission notes the acknowledgment of the Applicants that the wording of

the PPA is in error and that the price at which WRI could purchase the State Line interest is based on net book value and not on book value. (Transcript, 1219, 1251-52.) Rates under the PPA will be set by FERC on a cost basis after a review of the terms of the contract. The PPA rates are currently in effect subject to refund. If FERC ultimately sets rates lower than the original rate, the Applicants have committed to ensure that any refunds are passed through to the retail customers of KPL. (Transcript, 1237-38; Initial Brief, 92.)

Adjustments Relating to New Generation Capacity

61. The Commission agrees that adjustments related to the new generation capacity for additional off-system sales, additional customers and fuel savings should be made if they can be reasonably quantified. The Applicants argue that these adjustments are speculative and that they ignore the fact that the new capacity is to serve retail customers. (Brief, 135-38.) The Commission is not persuaded that adjustments relating to fuel savings and additional customers are sufficiently known and measurable. However, additional off-system sales are another matter. Although they contend that the new Gordon Evans and State Line capacity is intended only for retail customers, witnesses for the Applicants acknowledge that there will be increased sales from the new capacity if market conditions are right. (Transcript, 730-38, 765-66, 943, 1146-51, 2047-48, 2712, 2827-28.) The Commission also cannot ignore the increases in wholesale sales by the Applicants that have occurred in recent years. (Transcript, 766-69, 1149-57.) The Commission finds that the only credible conclusion is that the new capacity will be used by the Applicants for off-system sales. A credit for the value of these sales should be made in favor of the retail customers who are paying the costs of the new generation.

62. Specific dollar adjustments have been presented by CURB, Topeka, KIC and Wichita. The CURB witness relied on representations and projections made by the Applicants when

calculating the incremental revenue adjustment. This is a reasonable and valid method for determining the amount of the adjustment. The Commission adopts CURB's figure of $19,191,165 as an adjustment to operating revenue. (Crane direct, 39-43, Schedule 11-KPL.)

RATE BASE ADJUSTMENTS

63. The Applicants' proposed rate base for KGE is $1,363,609,832. The proposed rate base for WRI is $1,099,942,723. (Application, Vols. I and II, Section 3, Schedule 3-A, p. 1, line 6.) The following adjustments to rate base have been requested by the parties:

64. Accumulated Deferred Income Taxes. KPL paid an acquisition premium (AP) when it merged with KGE. An AP is a sum above book value that an acquiring company agrees to pay to shareholders of a company that is being acquired. In a 1991 Order, the Commission allowed the Applicants to begin amortizing approximately $12.9 million of the AP annually in 1995. The Commission stated that at that time, it was not allowing the AP to be put in rate base. The Applicants' only opportunity to earn a return of or on the AP would be from merger-related savings. Savings above the annual amortization amount were to be determined in the next rate case and shared 50-50 between ratepayers and shareholders. Pursuant to the Order, 50% of the savings above the allowed amortization would be included in cost of service. (November 15, 1991 Order in Docket Nos. 172,745-U and 174,155-U.)

65. In 1997, in Docket Nos. 193,306-U and 193,307-U, the annual merger savings were found to be $40 million. The amount above the $12.9 million amortization figure was approximately $27 million. Of the $27 million, 50% was to be imputed as an operating expense when calculating the Applicants' regulated earnings. Approximately $13.5 million was to be treated as an operating expense, and approximately $12.9 million per year was being amortized, for a total revenue requirement recovery related to the AP of $26.5 million. (193,306-U and 193,302-U January 15,

1997 Order.) The $26.5 million is recovered annually in rates through the operating income statement. (Transcript, 1924.)

66. Staff argues that the Applicants are receiving a return of and a return on the AP through rates, and that the effect of this is equivalent to rate base treatment. Staff asserts that its Accumulated Deferred Income Tax (ADIT) adjustment is a standard adjustment for rate base items and that if it is not accepted, the Applicants will receive an unfair benefit. Staff maintains that accepting this adjustment is not inconsistent with prior Orders. Staff's adjustment is also supported by Wichita. The Applicants rely on the 1991 Order which said that the AP was not being put in rate base. They argue that an ADIT adjustment was not contemplated and that no rate base offset is justified. (Proctor direct, 12, 51-57; Proctor surrebuttal, 11-19; Martin rebuttal, 7-8; McKnight rebuttal, 14-20; McKnight reply, 4-9; Transcript, 269-70, 1873-76, 1892-1938, 1978-81, 2011; Wichita Reply Brief, 4.)

67. The Commission accepts Staff's adjustment. ADIT was not mentioned at the time of the 1991 and 1997 Orders (Transcript, 270), but the Commission finds that this was because ADIT did not become an issue until after the $26.5 million amount was determined and the Applicants began to recover that amount. (Transcript, 1912-13, 1979-81.) As Staff indicates, including ADIT in rate base is standard to recognize for ratemaking purposes the cost-free capital provided from ratepayers related to differences between when expenses are deducted for regulatory and income tax purposes. There would be no need to specifically refer to such an adjustment in an Order. Including ADIT in rate base is a well-recognized regulatory accounting concept that is applied in a variety of situations to account for deferred income tax benefits related to rate base assets or for timing differences between when expenses are deductible for income tax purposes and financial reporting purposes. (Proctor direct, 53.)

68. There is no dispute that the Applicants are receiving both a return <u>of</u> and a return <u>on</u> the AP. (CURB Exh.12; Transcript, 1897.) This is equivalent to the AP being in rate base. A rate base item would normally have a related ADIT component. (Transcript, 1897-98, 1932, 2011.) The ADIT adjustment addresses the benefit the Applicants derive from collecting deferred income tax expense through the annual recovery of $26.5 million in merger savings. Through rates, the Applicants are collecting deferred income taxes related to the AP from ratepayers. (Proctor surrebuttal, 16.) The deferred income taxes are collected before the Applicants are required to pay income tax expense for the amortization of the AP. The result is an increase in expenses for purposes of calculating rates before the utility actually has to pay the expenses. Because the Applicants collect deferred income tax expenses related to amortization of the AP through rates, it is necessary to recognize the unamortized ADIT in rate base to avoid an unjust benefit accruing to the Applicants. (Proctor direct, 54-57; Proctor surrebuttal, 16; Transcript, 1896, 1916-18.)

69. Deferred income taxes are recovered as part of the $26.5 million annual recovery. The equivalent amount of AP in rate base is determined by calculating the present value of the annuity represented by annual collection of the $26.5 million through rates over a 34.83-year period. Using the rate of return ordered in this case to discount the annuity, the Commission finds that $208,644,237 of the AP is receiving equivalent rate base treatment. Further, because deferred income tax is collected as part of the $26.5 million, the Applicants are in effect receiving rate base treatment for the present value of the deferred income tax payments. That is, the Applicants receive a return on the present value of the deferred income tax payments. Because the Applicants receive a return on the present value of the deferred income tax payments and recovery of the deferred income tax essentially provides an interest-free loan from the ratepayers to the Applicants, it is necessary to decrease rate base by ADIT to avoid an unfair benefit to the Applicants. (Proctor

surrebuttal, 16; Transcript, 1917-19.) A cost-free loan from ratepayers should not be in rate base. The ADIT adjustment deducts the amount of taxes that correspond to the cost-free capital that the Applicants recover every year as part of the $26.5 million. The Applicants collect deferred income taxes from the ratepayers, and have the use of that money until the time when the taxes are ultimately paid. The ADIT adjustment deducts from rate base the amount of funds that are collected from ratepayers by the Applicants, but are yet to be paid. Without the ADIT adjustment, the Applicants would receive a revenue windfall from ratepayers. The ADIT adjustment, taking into consideration the ROR ordered, results in a decrease in KGE's rate base of $ 66,295,177, and a decrease in WRI's rate base of $16,698,284. (Proctor direct, 56, revised Exh. JMP-7; revised KGE and KPL Schedules A-3, Adjustment 1.)

70. Staff's ADIT adjustment is conservative. Instead of simply using the Applicants' records which show a return of the AP of $12,951,970 (CURB Exh. 12), and calculating the benefit to the Applicants over the remaining 35-year amortization period, Staff determined the present value of the cash-flow from the ratemaking treatment and based its ADIT adjustment on that number. While the Applicants' records would have supported the argument that the $26.5 million AP recovery is equivalent to placing $453 million of the AP in rate base, Staff concluded that it was more appropriate to use its methodology which finds that the recovery is equivalent to having approximately $220.6 million of the AP in rate base. Staff's calculations result in a lower ADIT adjustment. (Proctor direct, 53, 56; Transcript, 1873-76, 1897, 1909, 1926-29, 1933-35.) [Given the rate of return ordered in this case, the recovery is equivalent to having in rate base the $208 million figure stated above, instead of the $220 million discussed at the hearing.]

71. The Applicants assert that Staff has failed to consider that they are paying current income taxes on the $26.5 million that they recover. Staff did consider this, but stated that it was

not relevant because the $26.5 million had been grossed up for income taxes. (Transcript, 1915-16.) The return of the AP was approximately $7.8 million annually. In the 1997 Order, the amount was set at $12.9 million to take into account the income taxes that would be paid. (Transcript, 1899-1900.) That is, it was "grossed up" for income tax expense to recognize the income tax expense related to the amortization of the AP. Because the current income taxes were anticipated and accounted for when setting the $12.9 million recovery amount, those current taxes are not an issue now. The payment of current income taxes simply represents the Applicants paying off the cost-free capital provided by ratepayers through the Applicants' previous recovery of deferred income tax expense. The Applicants also contend that Staff is trying to "create" deferred taxes. This is incorrect. The deferral of income taxes is recorded on the books of the Applicants. As noted above, this is not unusual and is handled through a standard adjustment for ADIT.

72. LaCygne Sale/Leaseback. In 1987, the Commission approved the sale by KGE of its 50% undivided interest in LaCygne Unit 2 and addressed treatment of KGE's sale and leaseback transaction. The Order notes the obvious benefits of the transaction to KGE, and then states:

> Of equal importance to the Commission is the benefit to the customer. KGE contends the benefits of the transaction will be reflected in its cost of service. KGE proposes to amortize the book gain on the sale of LaCygne 2 to its Kansas jurisdictional cost of service over the life of the lease transaction. KGE also proposes to reduce its rate base by the book value of LaCygne 2, **reflect the unamortized gain as a reduction in rate base for future rate cases** and include the benefits of the use of the proceeds from the sale in its cost of service. Docket No. 156,521-U, September 17, 1987 Order, p. 11 (emphasis added.).

73. Staff and KIC propose a rate base adjustment to recognize cost-free capital created from the gain on KGE's sale of LaCygne in 1987. They state that by the terms of the 1987 Order, the gain from the LaCygne sale funds are to be considered cost free capital in future rate cases. KIC also emphasizes that this would be the fair and reasonable treatment regardless of any specific

language in the Order. (Proctor direct, 13, 58-61; Exh. JMP-8, Sch. 1; Dittmer direct, 15-18; KGE Update Schedule B-1; Dittmer surrebuttal, 20-23.)

74. The Applicants do not dispute what the Order says, but claim that the Order is in error. (Rohlfs rebuttal, 31.) They discuss the unique characteristics of KGE's regulatory history and state that the intended benefits from the Order have already been recovered. (Rohlfs rebuttal, 23-25, 29-39; Rohlfs reply, 2-9.)

75. This adjustment was raised by Staff in the1997 rate proceeding involving KGE and WRI, but that case was settled and the adjustment was not ruled upon. Docket Nos. 193,306-U and 193-307-U, January 15, 1997 Order, pp. 23-25, ¶¶ 43 and 45. The Applicants argue that making the Staff and KIC adjustment would give all the benefits of the gain to ratepayers, contrary to *Kansas Power & Light Co. v. Kansas Corporation Commission*, 5 Kan.App.2d 514, 620 P.2d 329 (1980), *rev. denied* 229 Kan. 670 (1981). In its Reply Brief, KIC correctly states that the LaCygne transaction is not an outright sale of utility property (as was the case in the *Kansas Power & Light Co.* case), but was a refinancing transaction. (See 1987 LaCygne Order, pp. 9-11.) In addition, what the Court found objectionable in the *Kansas Power & Light Co.* case was the fact that ratepayers were receiving **all** of the profits from the sale. 5 Kan.App.2d at 529. That is clearly not the case here. The 1987 Order specifically referred to the substantial monetary benefits that KGE would receive as a result of the transaction. 1987 LaCygne Order, pp. 11-12.

76. In arguing against this adjustment, the Applicants focus on the wording of KGE's Application and the intent of KGE, but what is controlling is the language in the Order and the intent of the Commission. The Applicants should have sought reconsideration and appealed the 1987 Order if they disagreed with its ruling on future rate base treatment. The provisions of the 1987 Order are clear and reasonable, and will be followed by the Commission. The adjustment of KIC

and Staff is approved and results in a decrease of $86,496,813 to KGE's rate base. (Proctor direct, 58-61, Exh. JMP-8; Staff revised KGE Schedule A-3, Adjustment 2; Dittmer direct, KGE Update Schedule B-1.)

77. FAS 106/112. The Applicants seek to recover unamortized costs related to Financial Accounting Standards (FAS) opinions 106 and 112. FAS 106 and 112 deal with post-retirement benefits other than pensions and other post-employment benefits. The Commission previously allowed the Applicants to amortize 106 and 112 costs with an income stream from a company-owned life insurance (COLI) program. The Applicants later received Commission approval to use the income stream from an affordable housing tax credit (AHTC) program. The Applicants now want to eliminate the AHTC program and to include in rate base the net unamortized accumulated balance of deferred benefits from the prior programs. The Applicants emphasize that even though the unamortized 106 and 112 costs represent a non-cash deferral, their shareholders took the initial steps to fund these programs and have advanced funds to pay interest. The Applicants also request a five-year amortization period of the net deferred balance of 106 and 112 costs, stating that that is the period of time over which the costs were accumulated. (Stadler direct, 4-7; Stadler rebuttal, 2-10; Transcript, 1512-14.) The Applicants acknowledge that there has not yet been any cash outlay of funds. (Transcript, 1515-16.)

78. Staff, CURB and KIC maintain that the unamortized FAS 106/112 costs which the Applicants seek to recover is the result of an accounting change from recording the expense on an accrual basis instead of a cash basis. Because there has been no cash or cash-equivalent investment in the deferral balance, there is no basis for a return on the unamortized costs and rate base inclusion is not appropriate. Staff also posits that rate base treatment is not warranted because the unamortized costs do not have a high degree of permanency and the value will not continue at a fairly stable level.

Staff does not oppose the five-year amortization period, but CURB recommends a 10-year period and KIC recommends an 11-year period. KIC also argues that the Applicants should not be allowed to end the AHTC program. (Yates direct, 5-8; Dittmer direct, 18-23, 75-85; Crane direct, 32-36, 48-50; Transcript, 2278.)

79. Ending the AHTC program is a reasonable management decision. (Stadler rebuttal, 7-9.) The Commission accepts the five-year amortization period proposed by the Applicants. However, the Commission finds that Staff, KIC and CURB are correct in their arguments that rate base treatment of the unamortized deferred costs is not appropriate because there has not been a cash investment. The Applicants' request for rate base inclusion of the unamortized FAS 106/112 costs is a deviation from the standard regulatory treatment, and the Commission will not adopt it here. The Commission adopts Staff's adjustment, which decreases KGE's rate base by $12,848,903 and decreases WRI's rate base by $20,107,152. (Yates direct, Exh. DDY-3; revised KGE Schedule A-3, Adjustment 5, and revised KPL Schedule 3-A, adjustment 4.) The Commission also adopts Staff's recommendation that there should be external third party funding of the FAS 106/112 costs. (See Yates direct, 8.) Within 90 days of the date of this Order, the Applicants are to meet with Staff to discuss arrangements for such funding.

80. <u>Customer Deposits</u>. The Applicants included customer deposits in the capital structure. Although this is normally the preferred approach, Staff and KIC recommend that an alternative treatment be followed because of the complexity of the capital structure. Their adjustment deducts customer deposits from rate base and includes the related interest expense in the income statement as an operating expense. (Yates direct, 4; Dittmer direct, 30-31; Sch. B-6 KGE; Sch. B-4 KPL.) The Applicants have not objected to this treatment, and the Commission finds it to be reasonable. This adjustment decreases KGE's rate base by $5,897,654, and decreases WRI's rate

base by $5,957,526. (Yates direct, Exh. DDY-2; revised KGE Schedule A-3, Adjustment 4, and revised KPL Schedule A-3, Adjustment 3.)

81. Environmental Compliance Projects. The Applicants have asked for inclusion in rate base of costs associated with the Electrostatic Precipitator (ESP) at Jeffrey Energy Center and Continuous Emission Monitoring Systems (CEMS) at Tecumseh, Lawrence and Jeffrey Energy Centers. These are environmental compliance projects mandated by federal and state regulations. (Irwin direct, 2-6; Irwin rebuttal, 2-4.) Staff, KIC and CURB oppose the inclusion of the costs, arguing that the projects have not been completed and do not meet the requirements of K.S.A. 2000 Supp. 66-128(b). (Yates direct, 2-4; Crane direct, 28-29; Dittmer direct, 26-29.)

82. K.S.A. 2000 Supp. 66-128(b)(1) permits the Commission to include in rates utility property which has not been completed and dedicated to commercial service if construction of the property will be commenced and completed in one year or less. There is no dispute that the costs for the environmental compliance projects are known and measurable. Goodyear and Staff question whether the construction schedules are definite enough to meet the statute's timing requirements. (Transcript, 1808-15, 1818-24.) The Applicants state that work on the CEMS project began in January 2001 and will be completed in December 2001, and that the ESP construction will take place in October or November 2001. (Irwin rebuttal, 3-4; Transcript, 1809-10, 1820-21.) The Commission finds that the Applicants' evidence is satisfactory to meet the standard of K.S.A. 2000 Supp. 66-128(b)(1) and that the costs should be included in rate base.

83. Tree Trimming. The Applicants used budgeted 2001 amounts for their tree trimming costs. They submitted increased tree trimming expenses greater than those incurred during the test year. (Will direct, 8-9.) Staff, CURB and KIC maintain that budgeted amounts are merely estimates and are not known or determinable. (Rohrer direct, 6; Crane direct, 53-56; Suess direct, 15-16.) The

Commission agrees and accepts Staff's adjustment, which uses actual Year 2000 capitalized tree trimming costs and allocates the costs on the basis of the Applicants' transmission allocation percentage. The effect of this adjustment is to increase KGE's rate base by $44,128 and to increase KPL's rate base by $69,348. (Rohrer direct, 6; revised KGE Schedule A-3, Adjustment 7, and revised KPL Schedule A-3, Adjustment 5.)

84. Wolf Creek and LaCygne Software. Staff made an adjustment to allocate a portion of Wolf Creek and LaCygne software to FERC jurisdictional wholesale customers. Staff's allocation adjustment is based on the Applicants' plant allocations. (Rohrer direct, 5-6.) The Applicants do not contest this adjustment (Initial Brief, 158), and it is accepted by the Commission. This adjustment decreases KGE rate base plant by $101,267, and decreases KGE rate base accumulated amortization of the cost of the software by $50,435. (Revised KGE Schedule A-3, Adjustment 6.)

85. Reserve for Depreciation. CURB and KIC recommend updating the Applicants' reserves for depreciation through June of 2001. (Crane direct, 31-32, Schedule 6-KPL, Schedule 6-KGE; Dittmer direct, 23-26, KPL Update, Schedules B-3 and C-8; Transcript, 2445-46.) The Commission agrees that this adjustment is appropriate if plant additions during the same period are also considered. CURB's proposed adjustment does not include plant additions. KIC only considered this adjustment for KPL, using the actual data for plant and reserve additions through December 2000 and the Applicants' budgeted numbers from December 2000 through June 2001. The Commission finds that for the amount of this adjustment to be sufficiently known and measurable, it would be necessary to have the actual numbers for both KPL and KGE through June 2001. While the proposal is conceptually correct, there is insufficient evidence to adopt it.

86. Murray Gill Repair. During the test year, the generator in Murray Gill Unit 2 overheated and repairs were necessary. (Wages direct, 5-6.) KIC agrees that the need for and cost

of the repairs are not at issue (Reply Brief, 30), but that the Murray Gill adjustments should be rejected because KGE's rate base has been continuously and significantly declining. (Dittmer direct, 99-100.) The Commission does not find KIC's argument to be persuasive.

87. Coal Contract Buyout Costs. CURB recommends that unamortized balances and associated deferred income taxes related to the buyout of a coal contract be updated through June 2001. The amount being amortized each month is known and measurable, and is adopted by the Commission. The requested adjustment results in a net decrease to KGE's rate base of $812,639. (Crane direct, 36-37, Schedules 10-KGE and 11-KGE.)

INCOME STATEMENT ADJUSTMENTS

88. For KGE, the Applicants' proposed income statement shows revenues of $675,192,768 , expenses of $569,201,732, and operating income of $105,991,036. For WRI, the proposed income statement shows revenues of $569,874,837, expenses of $513,499,001, and operating income of $56,375,836. (Application, Vols. I and II, Section 3, Schedule 3-B, p. 1.) Numerous adjustments to revenues and expenses have been recommended by the parties.

89. In their Initial Brief, the Applicants state that they do not contest certain Staff and KIC adjustments. (Initial Brief, 158-59.) The Commission therefore accepts the following adjustments:

a. Staff's adjustment for the portion of Edison Electric Institute dues related to lobbying activities, public relations and advertising. The adjustment decreases KGE's operating expenses by $60,647, and decreases WRI's operating expenses by $87,789. (Rohrer direct, 11-12; KGE and KPL revised Schedules B-3, Adjustment 16.)

b. Staff's pro forma salary adjustment, which increases KGE's expenses by $75,889 and increases WRI's expenses by $56,897. (Rohrer direct, 14-15; KGE and KPL revised Schedules B-3, Adjustment 19.)

c. Staff's adjustment relating to expired railcar leases, which decreases KGE's operating expenses by $64,565, and decreases WRI's expenses by $204,235.) (Rohrer direct, 15-16; KGE and KPL revised Schedules B-3, Adjustment 20.)

d. Staff's adjustment to include lease payments from Protection One in rent expense. This adjustment decreases KGE's expenses by $98,737. (Rohrer direct, 18; KGE revised Schedule B-3, Adjustment 24.)

e. Staff's weather normalization and customer annualization adjustments, which increase KGE's revenues by $113,645, and decrease WRI's revenues by $219,060. These adjustments also increase KGE's fuel expenses by $40,325, and decrease WRI's fuel expenses by $3,013. (Rohrer direct, 18-19; KGE revised Schedule B-3, Adjustment 25, and KPL revised Schedule B-3, Adjustment 24.)

f. KIC's adjustment relating to an expired capacity and energy sale to Empire, and to corresponding fuel savings. The overall effect of this adjustment decreases KGE's revenues by $3,749,753. (Dittmer direct, 52-53; KGE Update, Schedule C-7.)

90. The Commission adopts the following adjustments, finding that they also do not appear to be contested by the Applicants:

a. Staff's adjustment to remove expenses for outside legal services, which decreases KGE's expenses by $271,545, and decreases WRI's expenses by $494,577. (Rohrer direct, 8; KGE revised Schedule B-3, Adjustment 10, and KPL revised Schedule B-3, Adjustment 12.)

b. Staff's adjustment concerning outside accounting services on restructuring options, which decreases WRI's expenses by $235,100. (Rohrer direct, 7-8; KPL revised Schedule B-3, Adjustment 11.)

c. Staff's adjustment to remove an extra payment for outside services made during the test year, which decreases KGE's expenses by $68,472, and decreases WRI's expenses by $86,712. (Rohrer direct, 8-9; KGE revised Schedule B-3, Adjustment 11, and KPL revised Schedule B-3, Adjustment 13.)

d. Staff's adjustment to remove expenses that were prior to the test year or related to the Applicants' non-regulated affiliate, which decreases KGE's expenses by $183,955, and decreases WRI's expenses by $249,071. (Rohrer direct, 9-10; KGE revised Schedule B-3, Adjustment 12, and KPL revised Schedule B-3, Adjustment 14.)

e. KIC's income tax adjustments concerning a nuclear fuel expense tax deduction and a Wolf Creek net operating loss carry forward deferred tax expense. These adjustments decrease KGE's income tax expenses by $536,562 and $133,174, respectively. (Dittmer direct 102-03, KGE Update Schedule C-12.)

f. Wichita's labor allocator adjustment, which decreases KGE's revenue requirement by $73,769. (Suess direct, 22-23, Exhibit NDS-7.)

g. Wichita's reverse dividend equivalent accrual adjustment, which decreases KGE's revenue requirement by $105,347, and decreases WRI's revenue requirement by $162,839. (Suess direct, 23-24, Exhibit NDS-8.)

h. CURB's adjustment to normalize the PeopleSoft software for an entire year, which results in a decrease in WRI's expenses of $194,499 after a percentage is allocated to FERC customers. (Ostrander direct, 50; Transcript, 2461.)

91. The Commission finds that Staff's adjustment relating to advertising, as revised, is not in dispute. Staff originally sought to eliminate advertising expenses related to promotion of utility services, goodwill, improvement of utility image, and economic development. (Rohrer direct, 16.) The Applicants did not contest the elimination of image and goodwill advertising, but maintained that advertising concerning economic development benefits customers and should not be eliminated. (Wages rebuttal, 2.) At the hearing, Staff rescinded its objection to economic development advertising. (Transcript, 2229.) The Commission will allow the expenses for economic development advertising, as given by Staff, and also accepts the remainder of Staff's adjustment. The effect is to decrease KGE's expenses by $125,233, and to decrease WRI's expenses by $156,799. (Rohrer direct, 16; Transcript, 2229; KGE and KPL Schedules B-3, Adjustment 21.)

92. There are several income statement adjustments that correspond to depreciation, new generation capacity, and rate base rulings. These adjustments are adopted by the Commission:

a. the depreciation rulings increase the Applicants' net operating income. For KGE, the increase is $16,170,045; and for WRI, the increase of $8,415,675 for WRI. There is also an amortization expense adjustment for intangible plant that increases KGE's operating income by $20,253.

b. the Commission accepted CURB's adjustment relating to additional sales from new generation facilities. This adjustment increases WRI's revenues by $19,191,165. (Crane direct, 39-43, Schedule 11-KPL.)

c. Staff's ADIT rate base adjustment requires a decrease in deferred income tax expenses of $1,903,393 for KGE, and a decrease of $479,422 for WRI. (Proctor direct, 557, revised Exh. JMP-7; KPL revised Schedule B-3, Adjustment 1.)

d. consistent with the rate base customer deposit adjustment, KGE's expenses are increased by $353,859, and WRI's expenses are increased by $ 357,452. (Yates direct, 4, Exh. DDY-2; KGE and KPL revised Schedules B-3, Adjustment 5.)

e. consistent with its adoption of Staff's rate base tree trimming adjustment, the Commission accepts Staff's income statement tree trimming adjustments. These adjustments decrease KGE's expenses by $900,219, and increase KPL's expenses by $107,156. (Rohrer direct, 11; KGE and KPL revised Schedules B-3, Adjustment 15.)

f. Staff's rate base adjustment to allocate a portion of software expenses to FERC customers was not contested. The income statement adjustment for related amortization of the cost of the software decreases KGE's expenses by $20,253. (Rohrer direct, 5-6; KGE revised Schedule B-3, Adjustment 14.)

93. The Commission finds that the expense for union retroactive pay claimed by the Applicants was for a time period outside of the test year and should not be allowed. The Commission adopts Staff's adjustment to remove this portion of the union retroactive pay, which decreases KGE's expenses by $112,058 and decreases WRI's expenses by $106,750. (Rohrer direct, 19-21.)

94. The Applicants included costs for Y2K retention incentive pay. The Commission agrees with Staff that this is a one-time, non-recurring expense which should not be included. This adjustment decreases KGE's expenses by $35,761, and decreases WRI's expenses by $45,288. (Rohrer direct, 21.)

95. The argument was also made that costs relating to Wichita's municipalization plans should be disallowed as one-time, non-recurring expenses. The Commission agrees with the Applicants that these costs relate to regulated activities and will likely continue for an unspecified period of time. (Wages rebuttal, 11.) The Commission will allow these expenses.

96. KIC and Wichita claim that supplemental distributions related to premiums paid for Nuclear Electric Insurance Limited (NEIL) insurance should be considered as recurring and included in cost of service. (Dittmer direct, 96-98; Suess direct, 16-18.) The Applicants received NEIL distribution payments in March 2000 and March 2001, but argue that these are the only years

in which distributions have been made in the past 18 years, that the distributions were attributable to record investment income and extremely good loss experiences, and that these factors no longer exist and supplemental distributions are not expected to continue. (Wages rebuttal, 6-7.) The Commission does not find the evidence to be sufficient to conclude that these payments are recurring and accepts the Applicants' proposal to exclude the NEIL distribution from the rate filing.

97. The Commission previously expressed its willingness to consider adjustments outside of the test year that are known and measurable.

a. SPP Tariff. Staff supports the Applicants' proposal to place their retail load under the Southwest Power Pool (SPP) network tariff, but KIC, Wichita, Topeka and CURB have all raised objections to including the SPP expenses in the cost of service. (Holloway direct, 44; Dittmer direct, 68-74; Corrigan direct, 10-12; Bodmer direct, 40-41; Crane direct, 19.) The Commission has concluded that the costs are known and measurable, and that placing retail loads under the SPP tariff is reasonable and will improve reliability of electric service. (Dixon direct, 3-9; Dixon rebuttal, 2-13; Transcript, 1102-05.) The SPP expenses are allowed, and Wichita's requested adjustment for point-to-pont transmission service is not necessary. (Suess direct, 20-22; Dixon rebuttal, 5-6.) At the hearing, the Applicants stated their agreement that the cost to ratepayers should be adjusted as the SPP fee paid by the Applicants changes, and that an automatic adjustment clause might be reasonable. (Transcript, 1096-97, 1100.) The Commission directs Staff and the Applicants to discuss possible methods for adjusting the expense paid by ratepayers.

b. Company Owned Life Insurance. Both KIC and CURB state that the income from company owned life insurance (COLI) through June 2001 is actuarially determined and should be included. (Dittmer direct, 92-93; Crane direct 53.) The Commission finds that this additional revenue is known with certainty and will adopt CURB's adjustment of an increase in KGE's revenues of $1,410,909. (Crane direct, Schedule 16-KGE.)

c. Pension Expense. KIC argues that pension expense should be adjusted, based on actuary projections for 2001. This adjustment is based on records of the Applicants and is sufficiently definite to justify inclusion. The adjustment decreases KGE's expenses by $2,047,032, and decreases WRI's expenses by $3,938,700. (Dittmer direct, 93-96, KGE Update Schedule C-17, KPL Update Schedule C-14.)

d. Postage. KIC acknowledges that the postage increase outside of the test year is unavoidable and will be incurred by the Applicants. (Dittmer direct, 102; Transcript, 2454-55.) The Commission finds this expense to be known and measurable. (Wages rebuttal, 15.)

e. Property Taxes. Staff proposed two property tax adjustments. The first adjustment, which is not contested by the Applicants, reflects the difference between current actual property taxes billed to the Applicants and property taxes included in the test year cost of service. This adjustment decreases KGE's property taxes by $2,044,541, and increases WRI's property taxes by $1,552,658. The second adjustment relates only to WRI and reverses the estimated property taxes related to the new Gordon Evans units. Staff states that this amount is not known and measurable at this time and that WRI can request a surcharge under K.S.A. 2000 Supp. 66-117(f) if there is an additional increase. This adjustment decreases WRI's taxes by $1,888,889. The Applicants argue that seeking a surcharge under K.S.A. 2000 Supp. 66-117(f) would be confusing to customers and that the full property tax amount sought should be included. (Rohrer direct, 12-13, revised KGE and KPL Schedules B-3, Adjustment 17; Wages rebuttal, 7-11; Transcript, 2237-38.) The Commission finds Staff's position to be reasonable. The estimated tax amount is uncertain because the applicable mill levy has not yet been determined. The parties agree that there is a statutory remedy for the Applicants if an increase in WRI's property taxes makes a surcharge necessary. The Commission adopts both of Staff's property tax adjustments.

98. The Commission finds that the following requested adjustments have not been sufficiently supported by the evidence and rules in favor of the Applicants:

a. KIC's adjustment to reject the increase in liability insurance for directors and officers. (Dittmer direct, 96-97.)

b. Adjustments by CURB and KIC to disallow costs relating to new administrative positions. (Crane direct, 47-48; Dittmer direct, 86-88.) [The Commission has previously accepted Staff's pro forma salary adjustment.]

c. CURB's adjustment concerning the cubicle size of leased office space. (Ostrander direct, 46-49.)

99. Several parties suggest that the Commission exclude all of the charitable donations made by the Applicants. The controlling statute, K.S.A. 2000 Supp. 66-101(f), permits the Commission to disallow up to 50% of donations. Consistent with this, the Applicants only requested recovery of 50% of their donations. (Wages rebuttal, 5.) It appears that the Applicants are requesting recovery of half of their total donations, with none of the donations assigned to wholesale customers or non-regulated operations. (See Crane direct, 57.) The Commission finds that it is necessary to make these allocations and then appropriate to disallow 50% of the amount that is

properly assigned to retail electric customers. To accomplish this, the Commission will begin with the total contribution amounts of $792,810 for KGE and $889,806 for WRI. (KGE Application, Section 9, Schedule 9-C, Adjustment 9; WRI Application, Section 9, Schedule 9-C, Adjustment 8.) To these amounts, the Commission will apply Staff's residual allocation factor of 62.5% for regulated activities (see Proctor direct, 63), and the retail percentage based on FERC Account 930.2 [98.0005% for KGE; 93.3583% for WRI.] The resulting numbers are the amount of total donations that should be attributed to retail customers. The Commission disallows 50% of these amounts, and will permit a donations expense of $242,799 for KGE, and a donations expense of $259,596 for WRI. The Applicants included donations of $396,405 for KGE and $444,903 for WRI. The Commission's adjustment to the filed amounts results in a decrease of $153,606 for KGE, and a decrease of $185,307 for WRI. The Commission does not accept KIC's request that the Applicants be required to give recognition to ratepayers when making contributions. The Commission also does not accept the argument that it is improper for donations to be made through a charitable foundation.

100. Wichita requests an adjustment related to an apparently large expense entry made in FERC Account 557. The Applicants' response is that this involves hedging activities and that the entries in Account 557 for expenses are offset by entries in Account 451 for revenues. (Suess direct, 18-20; Wages rebuttal, 16; Transcript, 1466-75, 2580-86, 2928-32; Applicants' Exhibit 22.) The Commission finds the explanation of the Applicants to be reasonable and denies the adjustment.

101. The Applicants' power marketing activities were discussed extensively during the proceeding. The Applicants maintain that there are no power marketing expenses in the rate case and that profits from asset-based transactions are credited to retail customers. The Applicants state that ratepayers should not be subjected to the risks and potential losses from non-asset based transactions. In their Briefs, Topeka, KIC, Wichita and CURB raise questions about the practices

of the power marketing group and the manner in which transactions are classified. They argue that the power marketing group benefits from its association with the regulated utility and that there should be some recognition of the trading profits from non-asset based transactions in rates. The Commission has determined that a sharing of profits without a sharing of losses is not fair, and that ratepayers should not be at risk for potential losses. Accordingly, no adjustment will be made. However, the Commission also finds that information about the operations of the power marketing group was not sufficiently clear and that further review is warranted. This is a difficult area in which there is interaction between regulated and non-regulated activities. The Commission agrees with the witness for KIC that the lack of an audit trail and the complexity of these transactions are causes for concern. (Transcript 2450-51.) The Commission therefore orders that the Applicants file, within 30 days of the date of this Order, their written procedures for differentiating, classifying and tracking asset and non-asset based transactions. The Commission further orders that there be a thorough review of the Applicants' power trading activities and procedures by Staff or by an independent third-party approved by Staff. Definite plans for the timing and details of this review are to be formalized on or before December 17, 2001.

102. The Applicant used a three-year average ratio when calculating their bad debt expense. They state that the test year amount was unusually low and has increased tremendously, in part due to joint billing of electricity and natural gas services. The Applicants maintain that the benefits to customers from joint billing far outweigh the bad debt expense that would be incurred in this case. Staff and KIC recommend that the expense be based on the Applicants' actual test year bad debt expense. (Williams rebuttal, 2-8; Rohrer direct, 13-14; Dittmer direct, 88-90; Transcript, 1495, 1508.) Although the Commission does have some concern about electricity customers paying an expense related to high natural gas prices (Transcript, 2239-40), the Commission has concluded

that bad debts for the electric utilities will, in fact, be higher than those shown in the test year, and that the Applicants' three-year average ratio is reasonable.

103. Reserve normalization concerns accounts for injuries and damages to third parties, environmental costs, and property insurance associated with storm damages. For their reserve normalization adjustment, the Applicants used a three-year average. They argue that the three-year average is the method generally used. (Wages rebuttal, 14.) Staff argues that a five-year average should be used because it will provide a more level and accurate historical picture. (Kuzelka direct, 17-18.) Staff's five-year data shows large variance in the charges to this area over the years. The Commission concurs with Staff's recommendation and finds that using five years provides a better view of normalized expenses. The effect of this adjustment is to decrease KGE's expenses by $1,281,016, and to increase WRI's expenses by $147,313. (Kuzelka direct, Exhibit RLK-7.)

104. A number of adjustments relating to employee compensation and benefits have been proposed. (Rohrer direct, 17-24; Ostrander direct, 51-57.) The Commission does not accept Staff's adjustments relating to legal, tax, and financial services, severance pay, real estate bonuses, or short-term incentives and bonuses. The Commission believes that the <u>structure</u> of the total compensation package is largely a matter for the Applicants' management to decide. However, as discussed below, the Commission does find that adjustments to the long-term benefits of stock options and restricted share units (RSUs) should be made.

105. The Applicants included expenses relating to benefits changes of $3,035,784 for KGE and $5,558,264 for WRI. These expenses were to terminate a stock options program and to replace it with a RSU program. (KGE and WRI Applications, Section 9, Schedule 9-C, Adjustment 3.) CURB contends that some of these expenses are not known and measurable, that other expenses are for one-time, non-recurring payments, that some of the expenses were based on estimated instead

of actual data, that the change to amortization over 3-4 years instead of 9 years is inappropriate, and that a greater percentage of these expenses (50%) should be allocated to non-regulated operations. The total CURB adjustment is a decrease in expenses of $5,518,979. (Ostrander direct, 51-57, Attachments BCO-2 and BCO-12.) The witness for the Applicants on these adjustments did not address CURB's issues in rebuttal testimony (see Wages rebuttal), and the CURB witness was not cross-examined in this area. (Transcript, 2466-91.)

106. The Commission finds that the Applicants have made no serious effort to oppose CURB's stock option and RSU adjustments. The adjustments are supported by data request responses from the Applicants. The Commission accepts CURB's adjustments. When allocated between KGE and WRI the result is a decrease in expenses of $1,910,558 for KGE, and a decrease in expenses of $3,332,369 for WRI.

107. There was no Wolf Creek refueling outage during the test year. The Applicants, Staff, CURB, KIC and Wichita all provided recommendations as to what the length of the outage should be, what units would replace the lost generation, whether natural gas fired generation would need to be used, whether an adjustment for higher coal costs should be made, and whether there should be an adjustment for natural gas prices. (Harrison direct, 6-10; Hodson rebuttal, 2-10; Hodson reply, 1-4; Holloway direct, 28-36; Holloway cross, 1-5; Crane direct, 50-53; Dittmer direct, 54-58; Suess direct, 5-15.) This fuel normalization adjustment is designed to reflect what would happen during a standard outage. The Commission has considered the arguments of the parties and concludes that this is best accomplished by Staff's adjustment. Staff relied upon the actual past performance and historical availability of plants during a Wolf Creek outage when formulating its adjustment. Staff did not assume optimal operating conditions, as the Applicants suggest, but based its recommendation directly on empirical facts. The Commission adopts Staff's adjustment, which

results in a decrease in KGE's expenses of $8,679,018, and a decrease in WRI's expenses of $2,116,120. (revised KGE and KPL Schedules B-3, Adjustment 7.)

108. The Applicants did not oppose Staff's proposal to use the Henry Hub 36-month natural gas futures price strip to set natural gas costs (Cita direct, 8-12; Transcript, 2269-70; Mathis rebuttal, 22), and the Commission accepts this method. Wichita's suggestion that a fuel cost recovery mechanism be reinstated is rejected. (Corrigan direct, 31-32.)

109. In 1997, in Docket No. 97-WSRG-486-MER, the Commission approved the joint application of WRI, ONEOK, Inc., and WAI, Inc. to approve various transactions and transfers related to the merger of their natural gas operations. The Order in Docket No. 97-WSRG-486-MER found that evidence in the case supported the potential for administrative costs resulting from the alliance of WRI and ONEOK to flow back to WRI's electric customers. The potential amount of costs shown by the evidence was in a range of $4.6 million to $5.2 million. To ensure that there was no detriment to WRI's electric customers from the ONEOK relationship, the Commission ruled that WRI would have the burden of showing in its next rate case that these potential costs have been offset, in whole or in part, by benefits attributable to the WRI / ONEOK alliance. (Kuzelka Direct Testimony, Exhs. RLK-1 and RLK-2.)

110. The Applicants presented testimony that there had been over $5.4 million in savings resulting from the alliance. These savings were in 11 categories, with the largest amount ($4.2 million) attributable to the WRI/ONEOK shared services agreement. (Harrison Direct Testimony, 12-19; Exh. KBH-2.) The Applicants explained that the type of savings were generally caused by being able to avoid the duplication of costs, achieving volume discounts, or having one vendor for both entities. (Transcript, 1142-43.)

111. Staff conducted discovery to attempt to verify the claimed savings. Ultimately, Staff

disputed the savings, arguing that the Applicants had not met the burden of furnishing adequate supporting documentation to prove any savings or to meet standard auditing guidelines. Staff stated that it would be important to have historical baseline information in order to determine what changed after the alliance. Staff also concluded that some of the amounts submitted were simply not supported. Staff acknowledged that it was likely that there were savings of some amount from the WRI/ONEOK alliance, but emphasized that the burden was on the Applicants and they had not met it. (Kuzelka Direct Testimony, 3-17; Transcript, 2282-2304.)

112. Staff submitted an alternative position in case the Commission determined that some savings should be recognized. Under the alternative, Staff concluded that there was evidence of savings in 4 of the categories, totaling $4,035,987. Staff recommended that only 50% of the savings be attributed to the Applicants, and that savings of $2,017,090 be recognized. (Kuzelka Direct Testimony, 9-17.)

113. The Commission finds that the Applicants have not met the burden of establishing the level of savings, but that it is undisputed that some savings did result from the ONEOK relationship. In order to properly establish savings, the Applicants would have needed to demonstrate baseline costs and provide credible documentation to show savings from sources outside of the utility. While this was not done, the Commission does not want to ignore the acknowledged fact that there has been some level of savings, and will adopt Staff's alternative savings estimate of $4,035,987. However, the Commission does not accept Staff's recommendation to only consider 50% of the savings because it is not supported by the Stipulation and Agreement or the Order in Docket No. 97-WSRG-486-MER. The amount of necessary savings was identified as $4,600,000 to $5,222,000. The difference between $4,600,000 and the accepted level of savings ($4,035,987) is $564,013, and this amount is imputed to the cost of service as an income statement adjustment.

This adjustment decreases KGE's expenses by $284,247, and decreases WRI's expenses by $279,766.

114. The primary allocation adjustment proposed concerns executive compensation. The Applicants allocated 34% of the compensation for seven executives to non-regulated activities, based on an average of the fixed time allocations for the executives. (Transcript, 1688-91.) CURB initially adjusted this to 50%, and then later increased the percentage to 60%. The 50% number was based on CURB's review of corporate activities and was a weighted average of the seven executive officers. The 60% number is based largely on a review of aircraft logs. (Ostrander direct, 19-20; Attachment BCO-2; Ostrander supplemental direct, 15.) Staff allocates the salaries and benefits for nine corporate officers between regulated and unregulated operations. For eight of the officers, Staff allocates 37.5% of their compensation to unregulated operations. For the ninth officer (Douglas Lake), Staff allocates 100% to unregulated operations. The 37.5% is Staff's residual allocation factor, and is based on the percentage of WRI's investment and common equity in unregulated operations. (Proctor direct, 13-15, 62-75; Exh. JMP-10, Sch. 1; Exh. JMP-9, Sch. 1.)

115. The Commission must first comment on the deficiencies in the Applicants' allocation evidence. There was a fundamental problem with the manner in which Flaherty's review was designed. He simply looked at the allocation process being used, asked whether it was consistent with the process designed to be used originally, and evaluated whether the employees understood the process and were properly implementing it. (Flaherty direct, 4-6; Flaherty rebuttal, 5-8; Transcript, 1682-83, 1705, 1708.) This does not answer the basic question before the Commission, which is whether the allocations themselves are fair and reasonable. The Applicants focused on whether the procedures were being understood and followed, not on whether the procedures were the correct ones. The Commission finds that the Applicants' testimony should be given only

minimal weight because of this failure to address the relevant issue.

116. The Commission further notes several alarming aspects of the allocation procedures. The allocation system was designed in 1992, prior to the time when the Applicants expanded their operations out of the public utility arena. The Applicants concede that their operations have changed significantly since 1992. (Flaherty rebuttal, 5; Transcript, 1678-79, 1683-84, 1698.) The Applicants' witness looked at broad cost categories and did not consider any particular individual employees. (Transcript, 1686-90, 1695, 1705, 1802.) The executive officers make an annual estimate of the proportion of time that will be spent on regulated and non-regulated matters. No time sheets are kept. (Transcript, 248.) Instead, the estimated fixed percentage is used. At the end of the year, the executives can revisit the time allocations and make changes if they desire. For rate case allocations, an average of the executives' fixed time percentages was calculated, and this resulted in 34 % of the expenses being allocated to non-regulated activities. (Transcript, 1691,1701-02, 1719.) However, very few records or documentation of the process used to review and evaluate the allocation procedures were retained. (Transcript, 1756-66.)

117. A system that relies on an estimate made once a year, with no formal attempt to verify the accuracy of that estimate, is woefully insufficient to be used as a means of determining what expenses should be paid by ratepayers. The Commission finds that the criticisms of the Applicants' allocation methodology are valid. The Commission cannot stress too strongly the importance of properly allocating costs. The Applicants have the obligation to provide credible evidence to prove how time is spent before asking that ratepayers bear the expenses. Ratepayers should not be at risk for paying expenses for non-regulated activities. While the Applicants agree with this fundamental premise in principle (Transcript, 287), their allocation procedures are clearly inadequate to serve as a means of fairly allocating costs between regulated and non-regulated operations. The current

haphazard procedures for executive allocations provide no assurance that electric customers are not paying costs related to non-regulated businesses.

118. The Commission finds that the existing allocation guidelines and procedures for executives are so deficient as to require immediate remedial action. Within 90 days of the date of this Order, the Applicants are to file with the Commission a revised methodology for allocating costs relating to executive compensation between regulated and non-regulated operations. The methodology must include a reasonable process for allocating time and expenses that is subject to verification by contemporaneous records and documents. The Commission finds that this is essential to protect ratepayers from unjustified charges and to ensure that expenses collected through rates are just and reasonable.

119. The Commission finds no rational basis for accepting the Applicants' proposed 34% allocation percentage; however, the allocation between regulated and non-regulated operations still must be determined as part of this case. Evidence from Staff and CURB presents the Commission with two other alternatives for allocating executive time and expenses. The Commission adopts Staff's recommendation that 0% of Lake's time be allocated to regulated activities. For the other executives, the Commission adopts Staff's 37.5% allocation factor, finding that this was derived in a reasonable manner and provides a basis for fairly allocating expenses. The Commission rejects the Applicants' claim that Staff's allocation is in error because Staff began with a number which had already taken allocations of 30% into account. Staff used the pre-allocation figures, based on information received from the Applicants during discovery. (Proctor direct, Exhibits JMP-9, 10 and 11.) The effect of these adjustments is to decrease KGE's expenses by $292,488, and to decrease WRI's expenses by $447,091.

120. Several other allocation issues have been raised. The Commission accepts CURB's

adjustment to allocate 50% of Board of Directors' fees to non-regulated activities. This adjustment decreases total expenses by $303,394, and is allocated between KGE ($136,464) and WRI ($166,930). (Ostrander direct, 43-44; Attachment BCO-2.) The Commission finds that CURB's requested adjustment relating to insurance costs was not established, and does not accept it. (Ostrander direct, 44-45.) Similarly, the Commission does not find a sufficient basis to extend CURB's executive allocation to other corporate officers, or to change the reimbursement relating to tax services, and denies those adjustments. (Ostrander direct, 39-42.) Both Staff and CURB propose adjustments to outside services. (Proctor direct, 15, 62-75; Ostrander direct, 58-64.) The Commission accepts Staff's adjustment, which is based on a review of invoices from vendors which provided consulting and legal services to the Applicants. This adjustment decreases KGE's expenses by $171,168, and decreases WRI's expenses by $1,589,304. (Exh. JMP-11, Sch. 1; revised KGE and KPL Schedules B-3, Adjustment 3.)

121. Staff and the Applicants have requested that the Commission find that the ground lease payment by KPL to KGE is appropriate. (Harrison direct, 3-4.; Holloway direct, 38-39; Staff Post-Hearing Brief, 36; Applicants' Reply Brief, 42.) The Commission finds the lease payment to be reasonable. The contract is currently pending in Docket No. 00-KG&E-1122-CON, and the Commission will enter a separate order relating to the contract in that docket.

122. Rate case expenses are generally amortized over a three-year period, and the Commission will follow that practice in this case. (See Rohrer direct, 24; Transcript, 2245-46.) An adjustment for rate case expense will be made as soon as expenses have been determined.

123. A final adjustment for current income taxes is necessary to reflect the effect of the Commission's rulings. (Rohrer direct, 24.) This adjustment decreases KGE's operating expenses by $7,788,533; and decreases WRI's operating expenses by $13,085,528.

Other Issues

124. CURB suggests that the Commission review and upgrade its process for monitoring affiliate transactions in light of the fact that many utilities are becoming part of holding companies and affiliate transactions are increasing. CURB requests annual reporting of affiliate transactions and that utilities be required to demonstrate that the products or services could not have been obtained from non-affiliated sources or performed by the utility itself at a lower cost. CURB also asks the Commission to adopt policies related to cost shifting, to require competitive bidding, and to adopt asymmetric pricing standards. (Crane direct, 65-80; Brief, 53-61.)

125. The Applicants argue that it would be inappropriate to consider affiliate transaction standards and requirements in this rate proceeding, and that any such standards should not be applied only to the Applicants. The Applicants question whether such rules are necessary, but state that if the Commission decides to consider this matter, it should be through a rulemaking process in which all interested parties could participate.

126. The Commission will not adopt CURB's request in this proceeding. A review of affiliate transactions and related issues should be conducted, but will be on a generic basis.

127. Any adjustments or findings requested by the parties that are not addressed above have not been adequately explained or supported and are not adopted by the Commission.

Summary

128. Pursuant to this Order, the capital structure for the Applicants is 51.62% debt, 44.14% common equity, 0.90% preferred stock, and 3.34% accumulated deferred investment tax credits. The cost of long-term debt is 7.5062%; the return on equity is 11.02%,; and the rate of return is 9.0836%. For KGE, the rate base is $1,191,251,942, the required operating income is $108,208,538, and the revenue requirement is a decrease of $41,222,163. For WRI, the rate base is $1,057,249,109, the

required operating income is $96,036,259, and the revenue requirement is an increase of $18,470,583. The overall effect on the Applicants is a revenue requirement decrease of $22,751,580. Attachments summarizing these findings are attached. As determined in Docket No. 00-WSRE-855-COM, Orders No. 6 and 7, these rate changes are effective as of the date of this Order, and will begin accruing with interest at a rate of 9.0836% (the rate of return) as of the date of this Order.

PHASE II RATE DESIGN REQUIREMENTS

129. The Commission established a bifurcated process for reviewing the rates of the Applicants in Docket No. 00-WSRE-855-COM. This first proceeding determines revenue requirements. There will then be a second filing by the Applicants, in a new docket, for rate design purposes. <u>This rate design filing is to be made on or before September 20, 2001</u>. The filing of any petitions for reconsideration of this Order, or any appeal of this Order, will not delay the deadline for the rate design filing. The Commission intends to commence its consideration of the appropriate rate design for the Applicants in September of 2001, regardless of the status of this Order.

IT IS, THEREFORE, BY THE COMMISSION ORDERED THAT:

(A) These findings, conclusions and Attachments are the order of the Commission.

(B) Revenue requirements are set on an interim basis, subject to refund, as discussed in Paragraphs 8-14. The rates ordered above are effective as of the date of this Order, and will begin accruing with interest as of the date of this Order.

(C) On or before November 1, 2001, Staff is to initiate a generic review of quality of service standards, through either a formal docket or an administrative regulation process.

(D) Within 90 days of the date of this Order, the Applicants are to meet with Staff to discuss arrangements for funding of FAS 106/112 through an external third party.

(D) The Applicants are to file, within 30 days of the date of this Order, their written procedures for differentiating, classifying and tracking asset and non-asset based transactions. A power marketing review by Staff or by an independent third party approved by Staff is to be planned and scheduled on or before December 17, 2001.

(E) The Applicants are to file revised allocation procedures for Commission approval within 90 days of the date of this Order.

(F) The Applicants are to make a rate design filing, in a separate docket, on or before September 20, 2001.

(G) A party may file a petition for reconsideration of this Order within fifteen (15) days of the date of this Order. If service is by mail, three (3) additional days may be added to the fifteen (15) day time limit to petition for reconsideration.

(H) The Commission retains jurisdiction over the subject matter and parties for the purpose of entering such further orders as it may deem necessary.

BY THE COMMISSION IT IS SO ORDERED.

Wine, Chr.; Claus, Com.; Moline, Com.

Dated: 7-25-2001

ORDER MAILED 7-25-2001
Jeffrey S. Wagaman
Executive Director

ATTACHMENTS

Attachment 1	**KGE revenue requirement and capital structure**
Attachment 2	**KGE rate base adjustments**
Attachment 3	**KGE income statement adjustments**
Attachment 4	**WRI revenue requirement and capital structure**
Attachment 5	**WRI rate base adjustments**
Attachment 6	**WRI income statement adjustments**
Alphabetical Index	

INDEX

WESTERN RESOURCES, INC.
KGE - COMMISSION ORDER
REVENUE REQUIREMENT CALCULATION
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2000

LINE NO.	DESCRIPTION	AMOUNT
1	RATE BASE AS ADOPTED	$1,191,251,942
2	RATE OF RETURN ON RATE BASE AS ADOPTED (1)	9.0836%
3	NET OPERATING INCOME REQUIRED	108,208,538
4	PROFORMA OPERATING INCOME	133,033,555
5	DIFFERENCE	(24,825,017)
6	INCOME TAX FACTOR	0.602225
7	PROFORMA REVENUE INCREASE / (DECREASE)	($41,222,163)

(1) - COMMISSION APPROVED HYPOTHETICAL CAPITAL STRUCTURE:

	STAFF ADJUSTED AMOUNTS	CAPITALIZATION RATIO	COST OF CAPITAL	WEIGHTED COST OF CAPITAL
LT DEBT	$1,431,638,500	51.6213%	7.5062%	3.8748%
PREF. STOCK	24,857,600	0.8963%	4.5652%	0.0409%
EQUITY	1,224,219,500	44.1423%	11.0200%	4.8645%
POST 1970 ITC	92,633,236	3.3401%	9.0836%	0.3034%
TOTALS	$2,773,348,836	100.0000%		9.0836%

DOCKET NO. 01-WSRE-436-RTS

WESTERN RESOURCES, INC.
KGE - COMMISSION ORDER
SUMMARY OF ADJUSTMENTS TO RATE BASE
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2000

		AMOUNT
		*************
RATE BASE PER APPLICANT		$1,363,609,832
	ADJUSTMENTS TO RATE BASE ACCEPTED BY THE COMMISSION	
NO. 1	Recognize ADIT related to KGE recovery of merger savings	($66,295,177)
NO. 2	Recognize the unamortized gain on the LaCygne sale/leaseback	(86,496,813)
NO. 3	Include customer deposits as cost free capital	(5,897,654)
NO. 4	Reverse applicants pro forma FAS 106/112 adjustment	(12,848,903)
NO. 5	Allocate portion of intangible plant to wholesale (Software)	(50,832)
NO. 6	Reflect current calendar year level of capitalized tree trimming	44,128
NO. 7	Adjust KGE's coal contract buyout costs	(812,639)
	TOTAL ADJUSTMENTS TO RATE BASE	($172,357,890)
COMMISSION ADOPTED RATE BASE		$1,191,251,942

ATTACHMENT 2

DOCKET NO. 01-WSRE-436-RTS

WESTERN RESOURCES, INC.
KGE - COMMISSION ORDER
SUMMARY OF ADJUSTMENTS TO OPERATING INCOME
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2000

		AMOUNT
OPERATING INCOME PER APPLICANT		$105,991,036
	ADJUSTMENTS TO OPERATING INCOME ACCEPTED BY THE COMMISSION	
NO. 1	Amortization of ADIT related to Rate Base Adj. No. 1	$1,903,393
NO. 2	Allocation of additional officer compensation to non-reg.	292,488
NO. 3	Allocation of additional outside services expenses to non-reg.	171,168
NO. 4	Include interest expense on customer deposits	(353,859)
NO. 5	To reflect changes to depreciation rates and deferred income taxes	16,170,045
NO. 6	To reflect change in fuel normalization expenses	8,679,018
NO. 7	Decrease operating expenses related to WRI/ONEOK merger savings	284,247
NO. 8	Increase operating expenses related to reserve normalization	1,281,016
NO. 9	Decrease outside services expenses related to legal services	271,545
NO. 10	Decrease outside services expenses related to double payments in test year	68,472
NO. 11	Decrease outside services expenses related to expenses outside test year	183,955
NO. 12	Decrease amortization expense related to allocation of intangible plant	20,253
NO. 13	Decrease tree trimming expense	900,219
NO. 14	Eliminate portion of EEI dues related to lobbying and advertising	60,647
NO. 15	To decrease property taxes	2,044,541
NO. 16	Decrease the applicants bad debt adjustment	355,417
NO. 17	Increase salaries and related taxes for new personnel	(75,889)
NO. 18	Decrease operating expenses related to expired leases	64,565
NO. 19	Eliminate part of test year advertising expenses	125,233
NO. 20	Eliminate a portion of test year donations expense	153,606
NO. 21	Include rent revenue from non-reg affiliate	98,737
NO. 22	Weather normalization	73,320
NO. 23	Decrease operating expenses related to Y2K and union retroactive pay	147,819
NO. 24	To increase revenues based on current year COLI acturial study	1,410,909
NO. 25	Decrease pension expenses	2,047,032
NO. 26	Reflect actual amounts of restricted share units & change in amortization	1,910,558
NO. 27	Correct restricted share units for reverse dividend equivalent accrual	105,347
NO. 28	Allocate 50% of board of directors fees to non-regulated	136,464
NO. 29	To reflect expiration of the Empire 80 megawatt sale	(3,749,753)
NO. 30	To reflect city of Wichita's labor allocator adjustment	73,769
NO. 31	To eliminate Wolf Creek net operating loss carry forward deferred tax expense	133,174
NO. 32	To increase Applicants rate case expenses	(156,404)
NO. 33	Income taxes - current	(7,788,533)
	TOTAL ADJUSTMENTS TO OPERATING INCOME	$27,042,519
OPERATING INCOME ADOPTED BY THE COMMISSION		$133,033,555

WESTERN RESOURCES, INC.
KPL - COMMISSION ORDER
REVENUE REQUIREMENT CALCULATION
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2000

LINE NO.	DESCRIPTION	AMOUNT
1	RATE BASE AS ADOPTED	$1,057,249,109
2	RATE OF RETURN ON RATE BASE AS ADOPTED (1)	9.0836%
3	NET OPERATING INCOME REQUIRED	96,036,259
4	PROFORMA OPERATING INCOME	84,912,812
5	DIFFERENCE	11,123,447
6	INCOME TAX FACTOR	0.602225
7	PROFORMA REVENUE INCREASE / (DECREASE)	$18,470,583

(1) - COMMISSION APPROVED HYPOTHETICAL CAPITAL STRUCTURE:

	STAFF ADJUSTED AMOUNTS	CAPITALIZATION RATIO	COST OF CAPITAL	WEIGHTED COST OF CAPITAL
LT DEBT	$1,431,638,500	51.6213%	7.5062%	3.8748%
PREF. STOCK	24,857,600	0.8963%	4.5652%	0.0409%
EQUITY	1,224,219,500	44.1423%	11.0200%	4.8645%
POST 1970 ITC	92,633,236	3.3401%	9.0836%	0.3034%
TOTALS	$2,773,348,836	100.0000%		9.0836%

ATTACHMENT 4

WESTERN RESOURCES, INC.
KPL - COMMISSION ORDER
SUMMARY OF ADJUSTMENTS TO RATE BASE
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2000

		AMOUNT
		************
RATE BASE PER APPLICANT		$1,099,942,723
	<u>ADJUSTMENTS TO RATE BASE ACCEPTED BY THE COMMISSION</u>	
NO. 1	Recognize ADIT related to KGE recovery of merger savings	($16,698,284)
NO. 2	Include customer deposits as cost free capital	(5,957,526)
NO. 3	Reverse applicants pro forma FAS 106/112 adjustment	(20,107,152)
NO. 4	Reflect current calendar year level of capitalized tree trimming	69,348
	TOTAL ADJUSTMENTS TO RATE BASE	($42,693,614)
COMMISSION ADOPTED RATE BASE		$1,057,249,109

DOCKET NO. 01-WSRE-436-RTS

WESTERN RESOURCES, INC.
KPL - COMMISSION ORDER
SUMMARY OF ADJUSTMENTS TO OPERATING INCOME
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2000

		AMOUNT
OPERATING INCOME PER APPLICANT		$56,375,836
	ADJUSTMENTS TO OPERATING INCOME ACCEPTED BY THE COMMISSION	
NO. 1	Amortization of ADIT related to Rate Base Adj. No. 1	$479,422
NO. 2	Allocation of additional officer compensation to non-reg.	447,091
NO. 3	Allocation of additional outside services expenses to non-reg.	1,589,304
NO. 4	Include interest expense on customer deposits	(357,452)
NO. 5	To reflect changes to depreciation rates and deferred income taxes	8,415,675
NO. 6	To reflect change in fuel normalization expenses	2,116,120
NO. 7	Decrease operating expenses related to WRI/ONEOK merger savings	279,766
NO. 8	Increase operating expenses related to reserve normalization	(147,313)
NO. 9	Decrease outside services expenses related to accounting services	235,100
NO. 10	Decrease outside services expenses related to legal services	494,577
NO. 11	Decrease outside services expenses related to double payments in test year	86,712
NO. 12	Decrease outside services expenses related to expenses outside test year	249,071
NO. 13	Increase tree trimming expense	(107,156)
NO. 14	Eliminate portion of EEI dues related to lobbying and advertising	87,789
NO. 15	To decrease property taxes	336,231
NO. 16	Decrease the applicants bad debt adjustment	208,198
NO. 17	Increase salaries and related taxes for new personnel	(56,897)
NO. 18	Decrease operating expenses related to expired leases	204,235
NO. 19	Eliminate part of test year advertising expenses	156,799
NO. 20	Eliminate a portion of test year donations expense	185,307
NO. 21	Customer annualization & weather normalization	(216,047)
NO. 22	Decrease operating expenses related to Y2K and union retroactive pay	152,038
NO. 23	To recognize additional off-system sales	19,191,165
NO. 24	Decrease pension expenses	3,938,700
NO. 25	Reflect actual amounts of restricted share units & change in amortization	3,332,369
NO. 26	Correct restricted share units for reverse dividend equivalent accrual	162,839
NO. 27	Reflect a normalized level of Peoplesoft billings for an entire year	194,499
NO. 28	Allocate 50% of board of directors fees to non-regulated	166,930
NO. 29	To increase Applicants rate case expenses	(202,568)
NO. 30	Income Taxes - current	(13,085,528)
	TOTAL ADJUSTMENTS TO OPERATING INCOME	$28,536,976
OPERATING INCOME ADOPTED BY THE COMMISSION		$84,912,812

Comparison of AMEREN Regulation: Production Cost-of-Service Issues - MO PSC & FERC

	MO PSC	FERC
Rate Class Participants	Mo PSC Staff, OPC Staff, Industrials and any other stakeholder	FERC Staff, Mo PSC Staff, OPC Staff, customers and any other stakeholder
Regulatory Goal:	Resulting rates must be "Just, Reasonable, and not Unduly Discriminatory"	Resulting rates must be "Just, Reasonable, and not Unduly Discriminatory"
Memberships and Training:	Member of NARUC and Staff sent to NARUC Courses	Member of NARUC and Staff sent to NARUC Courses
Primary Data Source:	Cost-of-Service based on Uniform System of Accounts	Cost-of-Service based on Uniform System of Accounts
Test Year Practice:	Historic + Updated For Known and Measurable Changes	Historic + Updated For Known and Measurable Changes or Forecast (begins not more than 3 months after proposed effective date, and also requires that historic period data be provided.)
Prudence:		
Used and Useful	All costs and expenses must be Used and Useful. Mo PSC Staff, OPC Staff or any stakeholder may intervene and raise issues.	All costs and expenses must be Used and Useful. FERC Staff, Mo PSC Staff, OPC Staff or any stakeholder may intervene and raise issues, even the same issues raised before the Mo PSC.
Prudently Incurred Costs	All costs and expenses must be Prudently Incurred. Mo PSC Staff, OPC Staff or any stakeholder may intervene and raise issues.	All costs and expenses must be Prudently Incurred. FERC Staff, Mo PSC Staff, OPC Staff or any stakeholder may intervene and raise issues, even the same issues raised before the Mo PSC.
Rate Base Items:		
Plant	Directly Assigned except for allocation of General and Intangible Plant using Labor Ratios	Directly Assigned except for allocation of General and Intangible Plant using Labor Ratios
Accumulated Depreciation	Directly Assigned except for allocation of General and Intangible Plant using Labor Ratios	Directly Assigned except for allocation of General and Intangible Plant using Labor Ratios
Accumulated Deferred Income Taxes	Directly Assigned from Uniform System of Accounts	Directly Assigned from Uniform System of Accounts
Materials & Supplies	Directly Assigned from Uniform System of Accounts	Directly Assigned from Uniform System of Accounts
Prepayments	Functionalized and Allocated using Operating Expense Ratios	Functionalized and Allocated using Plant Ratios
Cash Working Capital	Negative Allowance Based Upon Lead-Lag Study Results	Allows One-Eighth of Annual O&M Expenses, Excluding Fuel and Purchased Power Costs (May consider Lead-Lag Study Results)
Expenses:		
Operations & Maintenance	Purchased Energy Allocated on Energy basis	Purchased Energy Allocated on Energy basis
	Purchased Capacity Allocated on Demand basis	Purchased Capacity Allocated on Demand basis
	Fuel Allocated on Energy	Fuel Allocated on Energy
	Operations and Maintenance Allocated on basis of Energy, but Operating Labor is Allocated using Demand Ratios	Operations and Maintenance Allocated on Energy or Demand, Based on basis of Each Subaccount
Administrative & General	Functionalized and Allocated on basis of Labor Ratios	Functionalized and Allocated on basis of Labor Ratios. Insurance is Allocated using Plant Ratios, and Regulatory Commission Expenses are Directly Assigned to applicable jurisdictions.
Depreciation	Directly Assigned except for allocation of General and Intangible Plant using Labor Ratios	Directly Assigned except for allocation of General and Intangible Plant using Labor Ratios
Other Taxes	Labor related allocated on Labor Ratios, Plant is Directly Assigned	Labor related allocated on Labor Ratios, Plant is Directly Assigned
Return	Applied to "Net Original Cost Rate Base"	Applied to "Net Original Cost Rate Base"
Income Taxes	Fully "Normalized", Interest Expense is Sychronized	Fully "Normalized", Interest Expense is Sychronized
Short-Term Energy Sales	Revenus from Short Term Energy Sales reduce Production Expenses. Allocated same as fixed costs.	Revenus from Short Term Energy Sales reduce Production Expenses. Allocated same as fixed costs.
Demand Allocation:	Traditionally, average of the 12 historic monthly peaks in the test year	Traditionally, average of the 12 historic monthly peaks in the test year
ROR Determination:	Discounted Cash Flow Analysis	Discounted Cash Flow Analysis
Effective Date of Rate Changes:	Effective 11 months after filing without Refund Protection, may become effective prior to 11 months under a settlement	Effective 60 days after filing (subject to refund with interest, until the final order). Suspension period may be either a one day or five month period.

Reported Equity Returns (ROE's) - Retail and FERC Cases

Year		Retail Electric	Retail Gas	FERC
1998	Number of Cases Reported (A)	10	10	3
	Average Equity Return	11.66%	11.51%	10.70%
	Range of Equity Returns	10.50% - 12.75%	10.90% - 12.20%	10.20% - 11.55%
1999	Number of Cases Reported (A)	20	9	3
	Average Equity Return	10.77%	10.66%	9.87%
	Range of Equity Returns	10.30% - 11.60%	10.25% - 11.25%	9.20% - 10.45%
2000 (B)	Number of Cases Reported (C)	19	17	9
	Average Equity Return	11.16%	11.09%	10.76%
	Range of Equity Returns	10.00% - 12.25%	9.56% - 11.60%	8.25% - 12.45%

Notes:

(A) Retail Source: Regulatory Research Associates, Inc.; FERC Source: FERC Web Site.

(B) October 1, 1999 - September 30, 2000.

(C) Retail Source: December 2000 Public Utilities Fortnightly: FERC Source: FERC Web Site.

Reported Equity Returns (ROE's) - Retail and FERC Cases

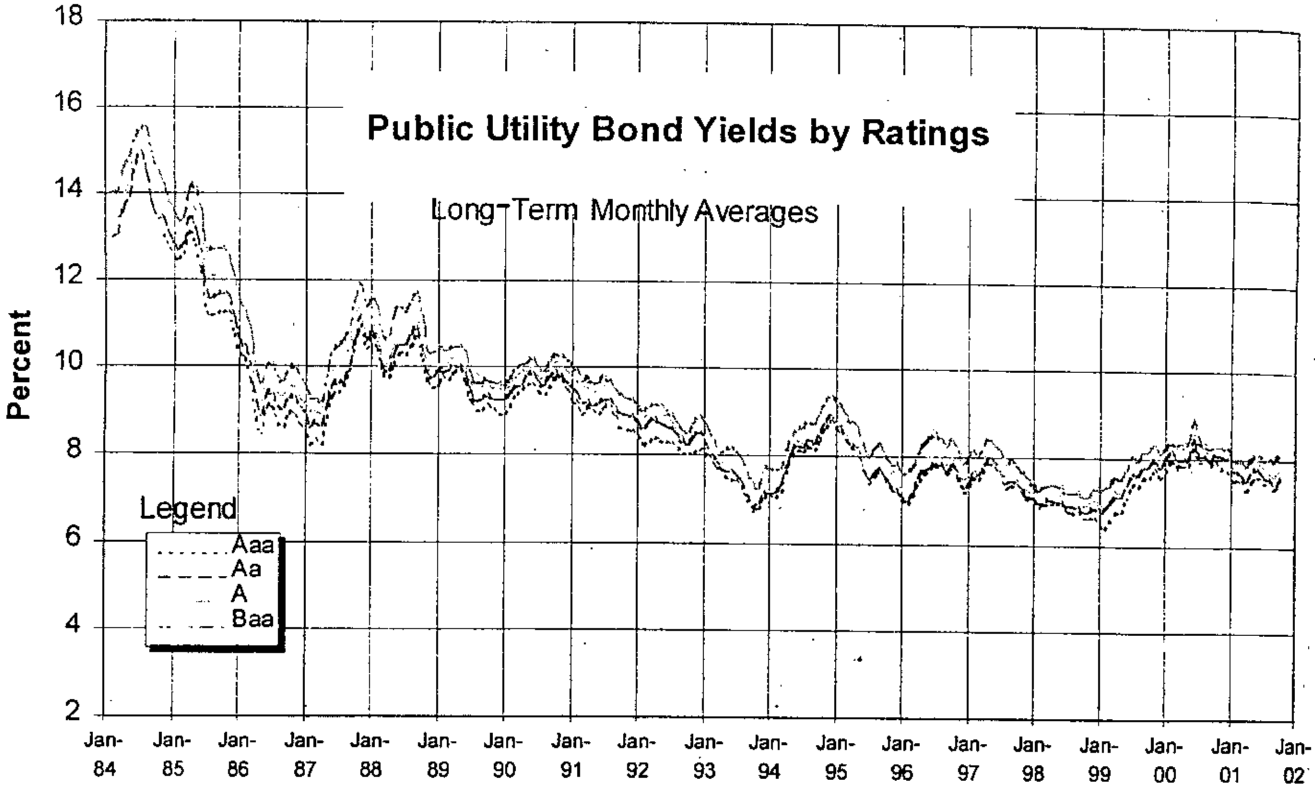
Year		Retail Electric	Retail Gas	FERC
1998	Number of Cases Reported (A)	10	10	3
	Average Equity Return	11.66%	11.51%	10.70%
	Range of Equity Returns	10.75% - 12.20%	10.93% - 12.10%	10.35%
1999	Number of Cases Reported (A)	20	9	3
	Average Equity Return	10.77%	10.66%	9.87%
	Range of Equity Returns	10.45% - 11.50%	10.50% - 11.15%	9.95%
2000 (B)	Number of Cases Reported (C)	19	17	9
	Average Equity Return	11.16%	11.09%	10.76%
	Range of Equity Returns	10.50% - 12.00%	10.25% - 12.00%	10.35% - 11.60%

Notes: [Extreme High and Low Equity Return Eliminated From Each Range.]

(A) Retail Source: Regulatory Research Associates, Inc.; FERC Source: FERC Web Site.

(B) October 1, 1999 - September 30, 2000.

(C) Retail Source: December 2000 Public Utilities Fortnightly: FERC Source: FERC Web Site.


Public Utility Bond Yields by Ratings
Long-Term Monthly Averages
Percent
18
16
14
12
10
8
6
4
2
Legend
Aaa
Aa
A
Baa
Jan-84
Jan-85
Jan-86
Jan-87
Jan-88
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Jan-90
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Jan-92
Jan-93
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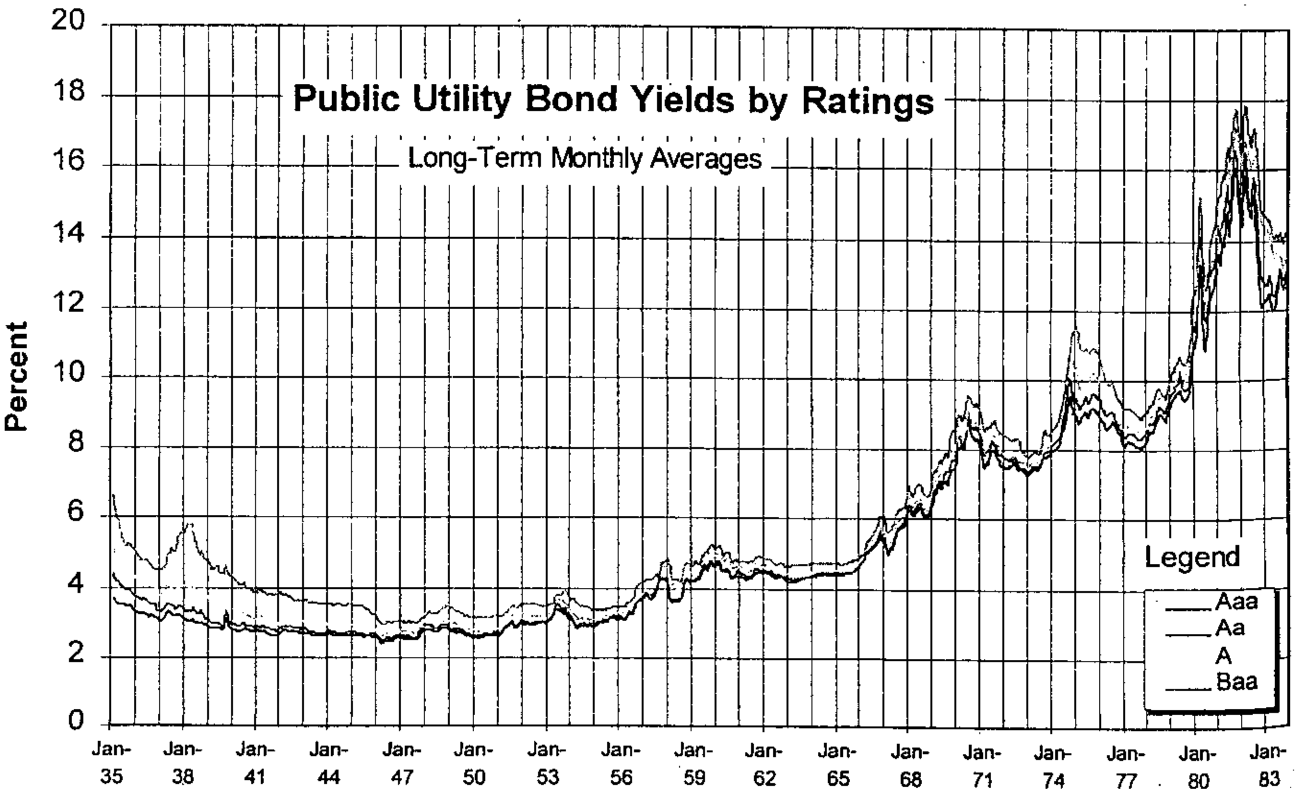
Jan-02

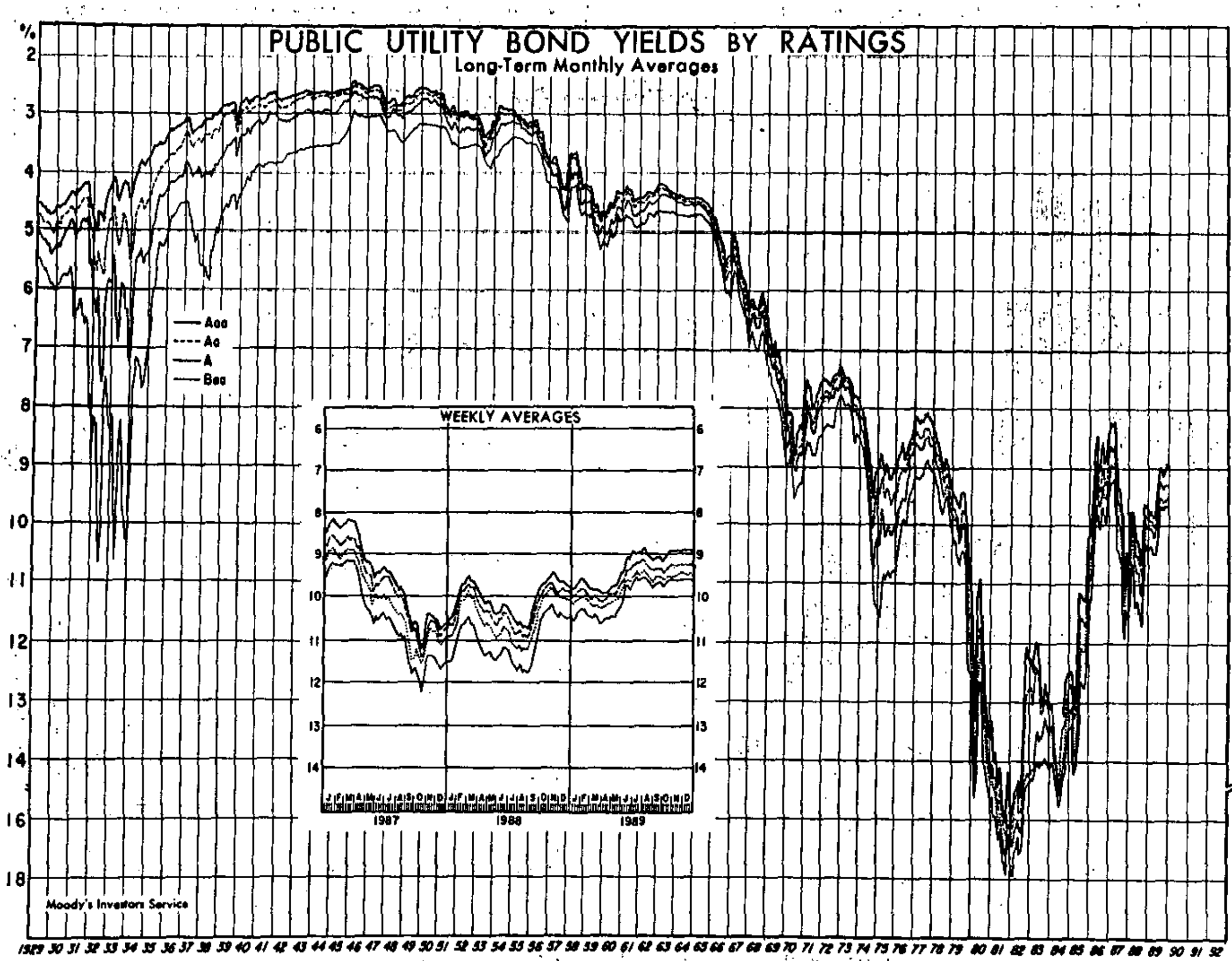

Public Utility Bond Yields by Ratings
Long-Term Monthly Averages
Percent
20
18
16
14
12
10
8
6
4
2
0
Legend
Aaa
Aa
A
Baa
Jan-35
Jan-38
Jan-41
Jan-44
Jan-47
Jan-50
Jan-53
Jan-56
Jan-59
Jan-62
Jan-65
Jan-68
Jan-71
Jan-74
Jan-77
Jan-80
Jan-83

Schedule 9

Historical Commission Rate of Return Decisions

Company	Case No.	Rate of Return on Net Original Cost Rate Base	Year	Moody's A avg. Util. Bond Yields	Moody's Baa avg. Util. Bond Yields
Union Electric	16,654	7.23%	1969	7.54%	7.93%
	17,107	7.87%	1971	8.16%	8.63%
	17,433	8.15%	1972	7.72%	8.17%
	17,972	8.42%	1974	9.50%	9.84%
	Average	**7.92%**		**8.23%**	
	ER-80-17	9.52%	1980	13.34%	13.95%
	ER-81-180	10.73%	1981	15.95%	16.60%
	ER-82-52	11.71%	1982	15.86%	16.45%
	ER-83-163	11.70%	1983	13.66%	14.20%
	ER-85-160	12.17%	1985	12.47%	14.53%
	Average	**11.58%**		**14.49%**	
Empire District Electric	17,816	7.29%	1973	7.84%	8.17%
	ER-81-209	10.25%	1981	15.95%	16.60%
	ER-83-42	10.75%	1983	13.66%	14.20%
KCPL	16,803	7.38%	1970	8.69%	9.18%
	17,419	7.99%	1972	7.72%	8.17%
	17,903	8.16%	1974	9.50%	9.84%
	ER-80-48	10.17%	1980	13.34%	13.95%
	ER-81-42	10.66%	1981	15.95%	16.60%
	ER-82-66	11.91%	1982	15.86%	16.45%
	ER-83-49	12.24%	1983	13.66%	14.20%
St. Joe Light & Power	16,913	7.14%	1970	8.69%	9.18%
	18,022	7.97%	1974	9.50%	9.84%
	ER-80-53	10.97%	1980	13.34%	13.95%
	ER-81-43	11.24%	1981	15.95%	16.60%
Utilicorp	16,569	7.30%	1969	7.54%	7.93%
	17,246	8.22%	1972	7.72%	8.17%
	17,763	8.22%	1974	9.50%	9.84%
	ER-80-118	9.65%	1980	13.34%	13.95%
	ER-81-85	10.01%	1981	15.95%	16.60%
	ER-82-39	10.47%	1982	15.86%	16.45%
	ER-83-40	11.23%	1983	13.66%	14.20%
Ameren	EC-2002-1	**8.31%** Staff rec.	2001	**7.48%**	8.03%
		(midpoint)	2002*	**7.57%**	0.00%

*Jan-Apr 2002



Schedule 11

Moodys Bond Record Jan '90