The level of performance needs to be defined so that the results of the performance can actually be measured and identified. The uniqueness or novelty of the performance would be examined to identify whether the better-than-expected performance was the result of happenstance or the result of superior effort.

The degree of organizational control a company has over its own performance determines, in part, the amount of influence that the company has over the ultimate result. The extent external factors outside the company's control affect performance should be a consideration in evaluating the company's operations.

The distribution scheme between shareholders and ratepayers of the better-than-expected performance would be evaluated in regards to issues of equity and reasonableness. The distribution would be judged against the result that would occur under traditional methods to ensure that no party was harmed by the distribution scheme or inequitably affected.

b. Identify each document that you relied on to respond to this Interrogatory or that in any way forms the basis for your answer to this Interrogatory.

<u>Staff Response</u>: **The Staff response is based on Staff knowledge and experience. The Staff did not rely upon any specific documents to develop its response or answer to this Interrogatory.**

51. Explain in as much detail as you can what you believe to be the attributes of good management of a utility.

Staff Response: Management is the process that involves the interfacing and coordination of people, capital, technology and time to achieve planned results. Within the exercise of these functions, management holds a responsibility to ratepayers and stockholders to strive to achieve all cost-justified efficiencies. The primary functions of management are usually defined as the functions of planning, organizing, directing and controlling. Other activities that are necessary to management's execution of these four primary functions include decision-making, coordinating, and communicating. Management must design processes and practices to ensure that the cycle is effectively completed. Failure to successfully execute any step in the management cycle, or any significant deficiency in executing a step, weakens management control, reduces the performance of the organization and increases operating costs.

"Good management" should be viewed as requiring superior or certainly better than average performance. To reach this "good management" level, a company should demonstrate a constant effort to improve its cost of service and quality of performance above the level to be expected from merely average management. A company should perform in a superior manner through the introduction of new methods and thresholds of performance that achieve significant results in the lowering of operating costs and improving the quality of service. A company's stakeholders, industry peers and customers should recognize the company as being a superior performer in the industry.

It is not unusual for management issues requiring Commission determination to occur. One of the more notable recent instances of that is when

UE sought to have the Callaway generating station reflected in rates. See *Re Union Electric Co.*, Report And Order, Case Nos. EO-85-17 and ER-85-160, 27 Mo.P.S.C. (N.S.) 183, 192-94 (1985).

a. Identify each document that you relied on to respond to this Interrogatory or that in any way forms the basis for your answer to this Interrogatory.

<u>Staff Response</u>: **The Staff response is based on Staff knowledge and experience and the following documents: The American Management Association Management Handbook – John J. Hampton, Editor - Third Edition, 1994 and The American Management Association Management Handbook – William K. Fallon, Editor - Second Edition, 1983. Direct Testimony of Arthur K. Wimberley in *Re Kansas City Power & Light Co.,* Case Nos. ER-85-128 and EO-85-185 (1985), in *Re General Telephone Company of the Midwest,* Case No. TC-87-57 (1987), and in *Re Southwestern Bell Telephone Co.*, Case Nos. TC-89-14 et al. (1988); and Direct Testimony of Deborah Ann Bernsen in *Re Kansas City Power & Light Co.*, Case Nos. ER-85-128 and EO-85-185 (1985).**

52. Explain in as much detail as you can how you know when a utility has good management, as you described good management in response to the preceding interrogatory.

<u>Staff Response</u>: **"Good management" should be perceived as existing whenever a utility performs consistently in an exceptional manner, producing positive results that are better than the industry norm. Good management can make itself apparent in how a company responds to difficult situations. A well-managed company will often foresee a situation, and be prepared to view it as both a challenge and an opportunity. While the company may be unable to**

avoid the difficulty in the end, it will manage the situation instead of letting the situation control the company.

From a practical standpoint, a well-managed company will exhibit strong positive characteristics that extend to the various facets of company operations. Execution of the planning, organizing, directing and controlling functions should support all areas of the company.

Good management will establish objectives that if achieved will result in the company being an industry leader in the areas that are of concern to its customers and other stakeholders. Such a company will provide high quality service at prices that other companies will target to remain effective and efficient. Good management will be associated with a company that offers products, charges prices and engages in practices that are recognized as among the best in the industry. Good management is fiscally responsible and does not accomplish its objectives through just a massive commitment of resources. Good management will thoroughly evaluate and document its decisions. It also monitors and evaluates the results of these decisions to determine the appropriateness of the decisions, and the effectiveness of its follow-through processes.

Performance indicators in a wide range of areas are valuable tools in making some initial, basic assessment of a company's management effectiveness. Good management may appear in performance indicators that show results superior to others in the industry respecting matters within management's control.

A thorough review and audit of a utility, including an objective management audit, is useful in determining the quality and effectiveness of management decisions made at the company. Such audits present both a historical and current picture of company operations.

a. Identify each document that you relied on to respond to this Interrogatory or that in any way forms the basis for your answer to this Interrogatory.

<u>Staff Response</u>: **The Staff response is based on Staff knowledge and experience and the following documents: The American Management Association Management Handbook - John J. Hampton, Editor - Third Edition, 1994 and The American Management Association Management Handbook – William K. Fallon, Editor - Second Edition, 1983; Direct Testimony of Arthur K. Wimberley in *Re Kansas City Power & Light Co.*, Case Nos. ER-85-128 and EO-85-185 (1985), in *Re General Telephone Company of the Midwest*, Case No. TC-87-57 (1987), and in Re *Southwestern Bell Telephone Co.*, Case No. TC-89-14 (1988); and Direct Testimony of Deborah Ann Bernsen in *Re Kansas City Power & Light Co.*, Case Nos. ER-85-128 and EO-85-185 (1988).**

53. From the perspective of investors or shareholders, what are the attributes of good management of a utility?

<u>Staff Response</u>: **The Staff has performed no study or analysis of the attributes of good management of a utility from the perspective of investors or shareholders.**

a. Explain in as much detail as you can the basis for your answer to this Interrogatory.

<u>Staff Response</u>: **See above response.**

b. Identify each document that you relied on to respond to this Interrogatory or that in any way forms the basis for your answer to this Interrogatory.

<u>Staff Response</u>: No documents were used to develop the response to this Interrogatory.

54. From the perspective of a utility's customers, what are the attributes of good management of a utility?

<u>Staff Response</u>: Customers expect the management of a utility to be experienced, competent and responsive in the managing and operation of the utility. In addition to receiving safe and reliable service at the lowest possible rates, utility customers focus on their actual experience when dealing with a utility. Utility customers are interested in their utility service needs and expectations being met in a manner as unobtrusive as possible to them.

Staff is aware of the general attributes that consumers expect from their utilities. Staff is also aware that some utility companies determine key service indicators important to their customers and make a commitment to meet these indicators by instituting service guarantee programs. Such programs financially compensate the customer if the company does not meet certain commitments, such as scheduled appointment times.

Utility customers want utility service provided at the lowest possible cost. In most cases, utility customers desire rates lower than what a utility is currently charging, or has requested in a rate proceeding, and lower than what Staff may have recommended in a rate proceeding. Staff has observed a general wariness on the part of utility customers respecting their utility providers. Some utility

customers perceive their utility companies are charging too much for the services they provide.

Utility customers want to be assured that they are receiving an ongoing supply of safe and reliable service at the lowest possible cost, and if there is a service interruption for any reason, utility customers demand service restoration promptly and with minimal disruption to their lives and businesses. Utility customers expect service personnel to respond to service calls promptly, within an agreed upon time, and they expect prompt and complete performance of all company commitments.

Utility customers want an easy and quick method of dealing with a utility when they have a question or problem relating to the payment of bills, service or other utility matters. Customer expectations include the ability to talk with a qualified person at the utility who can answer their questions, provide a requested service or address their problem or concerns in a courteous, accurate, prompt and responsive manner. If needed or desired, utility customers expect to talk with a supervisor.

Customers' bills are an important source of information for both the customers and the utility. Customers want a bill that is easy to read and understand. They expect utility bills to be accurate and provide useful information about the service and charges for such service. Once the utility company receives payment, customers want assurance that the company's procedures result in timely and accurate posting of their payment.

Utility customers receiving metered service prefer their meter to be read in a timely and accurate manner for billing purposes. They expect the service **meter to measure and record the use of their service accurately and believe the utility company is responsible for ensuring such accuracy.**

Utility customers desire a utility company that demonstrates an interest in meeting their needs, being responsive to their requests and inquiries and meeting or exceeding their expectations. Utility customers with special needs want assurance that the utility company has provisions to meet those special needs.

a. Explain in as much detail as you can the basis for your answer to this Interrogatory.

Staff Response: **The preceding Staff response is not an exhaustive list of the expectations of customers. The basis for the answer for this Interrogatory is the experience and knowledge of Wess Henderson, Debbie Bernsen, and Janet Hoerschgen. Mr. Henderson gained experience at the Commission as the Assistant Manager of the Rates Section of the Water and Sewer Department, and in his current position as Director of the Utility Operations Division. He has had the opportunity and the charge to respond to customer's questions, comments and complaints regarding utility operations in both formal and informal rate proceedings and public meetings. These questions, comments and complaints were respecting matters ranging from management in general to specifics regarding rates, service, safety, operations, finance, record keeping and billing. In some instances, utility customers demanded to have utilities sold due to poor management and operation.**

Ms. Bernsen has worked approximately 25 years at the Commission. During this time, she has worked as a Consumer Services Specialist and a Management Analyst. As a Consumer Services Specialist, she was responsible for receiving and investigating consumer billing questions, complaints and inquiries. In 1978, she joined the Management Services Department as a Management Analyst and since that time has performed numerous reviews of utility operations and control systems, as well as specific customer service reviews. She has also filed testimony in a number of instances on the issue of management control systems and customer service quality.

Ms. Hoerschgen has worked at the Commission for approximately 29 years. Her experience includes time as a Consumer Services Specialist and then, in her present position, as the Manager of the Consumer Services Department. She has had the opportunity to respond to consumer complaints and inquiries, participate in customer service reviews of utility companies, and address customer service concerns in rulemakings, complaints, rate cases and special investigations.

b. Identify each document that you relied on to respond to this Interrogatory or that in any way forms the basis for your answer to this Interrogatory.

Staff Response: **The Staff response is based on Staff knowledge and experience. The Staff did not rely upon any specific document to form the basis for its answer to this Interrogatory.**

55. What role does the service provided by a utility play in the economic development of the State of Missouri?

Staff Response: Utility services and the cost of those services are vital to the economy of Missouri because of their impact on the quality of life of each person living, working, traveling, or visiting in the State. Virtually every person and business in Missouri receives some form of utility service. Utility services are provided by investor-owned, customer-owned (cooperative), and government-owned (municipal) entities.

Utility services provide heating and cooling during extreme temperatures. They offer access to emergency services and vital information systems. They provide safe drinking water and assure the environmentally sound disposal of wastewater. Individuals and businesses that are unable to pay for utility services may be relegated to a substandard existence and even life threatening situations. Thus, the monies paid for utility services are generally not discretionary from a consumer's perspective.

The money that is paid for utility service is not available to buy the goods and services of new businesses seeking to establish themselves or existing businesses desiring to expand or maintain their current position. The cost of utility services affect the prices charged by and the profitability of most Missouri businesses.

The availability, quality, and cost of utility services impact the State's economic development. All of these components are interrelated and affect the State. It is purported that the availability, quality, and cost of utility services can be key factors in a business entity's decision regarding where to locate a new business, whether to relocate an existing business, at which location to expand an existing business operating at different sites in multiple states, or where to cutback or shutdown operations of an existing business operating at different sites in multiple states.

It is the vision of the Department of Economic Development (DED) "to make Missouri the best place to live, work, vacation, and conduct business." Among many other things, DED collects and interprets information regarding utility rates. This information is provided in response to specific company, community, or business inquiry or needs. Cost of living is a measurement that is identified in the DED Strategic Plan. Missouri is considered a more attractive state to live in if its cost of living is lower relative to other states. Cost of living is positively affected by a decline in the cost of utility services.

a. Explain in as much detail as you can the basis for your answer to this Interrogatory.

Staff Response: The Department of Economic Development's Strategic Plan does not extensively mention the role played by utility service in the economic development of the State of Missouri. Staff based its response on items that it identified from a draft of the Department of Economic Development's Strategic Plan for fiscal year 2002. Staff also reviewed the 1999-2000 Official Manual State Of Missouri (1999-2000 Missouri "Blue Book").

b. Identify each document that you relied on to respond to this Interrogatory or that in any way forms the basis for your answer to this Interrogatory.

Staff Response: The Department of Economic Development's Strategic Plan, the 1999-2000 Missouri Blue Book, page 322, and UE/Customer Share In The

Savings Plan attached to January 27, 1995 letter from Don Brandt to Ken Rademan, pages 6 and 10 (Exhibit 21 in Case No. EO-96-14).

56. On page 7 (lines 1-2) of the testimony of Ronald L. Bible, Mr. Bible makes the following statement: "it has generally been recognized that public utilities can operate more efficiently when they operate as monopolies."

a. Explain in as much detail as you can the basis for this statement.

<u>Staff Response</u>: Utility companies can supply service at lower costs if the duplication of facilities is avoided. This allows the use of larger and more efficient equipment, which results in lower per unit costs. For instance, it would likely cost more for two or more competing companies to maintain duplicate electric distribution systems to provide competing residential services to one household. This situation could result in price wars and lead to unsatisfactory and perhaps irregular service. For these reasons, exclusive rights may be granted to a single utility to provide service within a given territory. This also creates a more stable environment for operating the utility company. Utility regulation acts as a substitute for the economic control of market competition and allows the consumer to receive adequate utility service at a reasonable price.

The Staff notes *State ex rel. McKittrick v. Public Serv. Comm'n*, 175 S.W.2d 857 (Mo.banc 1943) (hereinafter referred to as *McKittrick*). In that case, Attorney General McKittrick sought review of a Commission order sustaining a joint application of Laclede Power & Light Company (LPL) and others to sell to Union Electric Company (UE) the property rights and franchises of LPL. The underlying Commission case was *Re Laclede Power & Light Co., et al.*, Case No.

10,263, Report And Order, 26 Mo.P.S.C. 266 (1943). The Court related that the Commission approved the application for the following reasons: (1) the merger would benefit the public because it would eliminate wasteful competition by the integration of two public utilities; (2) it would provide an opportunity for reducing the cost of electric service by eliminating duplicate facilities and organizations; (3) it would promote public safety by relieving congestion on public trafficways through the removal of duplicate distribution facilities; (4) it would improve the financial stability of the system, since LPL was not as financially stable as UE; and (5) it would provide better assurance of uninterrupted service to LPL's present customers since UE's system had large and more diversified facilities for service. 175 S.W.2d at 859. The Commission itself stated in its Report And Order as follows:

> This application seeks to unify under a single corporate and operating entity the electric public utility industry in St. Louis. There is no doubt that, in our modern economic system, complemented by adequate and efficient regulation, a single source of public service of a given nature is more desirable than two or more separate agencies. This principle is too well-known to require further elaboration here . . . .

26 Mo.P.S.C. at 269.

Among other things, Attorney General McKittrick charged that there was no showing that any benefit would accrue to the customers of LPL and UE from the merger. The court held that this issue was a question of fact and that the Attorney General had not shown by clear and satisfactory evidence that the order of the Commission was unreasonable or unlawful. The Court therefore

affirmed the Commission's order sustaining the joint application. 175 S.W.2d at 866.

b. Identify each document that Mr. Bible relied upon to make this statement.

<u>**Staff Response**</u>: **Staff's response is based on Mr. Bible's knowledge and experience and Commission Case No. 10,263.**

57. Explain in as much detail as you can all performance measures and evaluation criteria that you believe are appropriate for judging the success or failure of any past or future EARPs.

59. Explain in as much detail as you can what you believe to be the incentives, if any, created by or amplified by the EARPs, and explain in as much detail as you can the basis for that belief.

61. Explain in as much detail as you can the basis for the following statement in the Staff's EARP Report, at page 6: "The current EARP contains no stated performance measures or evaluation criteria on which to judge the success or failure of the EARPs."

63. Explain in as much detail as you can the standard by which you believe the "efficiency" of UE's "operations" should be measured, as you use those terms in item 3 on page 8 of the Staff's EARP Report.

65. Explain in as much detail as you can the standard by which you contend the "benefits" of the EARPs can be measured or evaluated "in terms of rates," as you state in item 2 on page 8 of the Staff's EARP Report.

67. Explain in as much detail as you can the standard by which you contend the "benefits" of the EARPs can be measured or evaluated "in terms of . . . credits," as you state in item 2 on page 8 of the Staff's EARP Report.

69. Explain in as much detail as you can the standard by which you contend the "benefits" of the EARPs can be measured or evaluated "in terms of . . . services," as you state in item 2 on page 8 of the Staff's EARP Report.

71. Explain in as much detail as you can the standard by which you contend the "benefits" of the EARPs can be measured or evaluated "in terms of . . . quality of service," as you state in item 2 on page 8 of the Staff's EARP Report.

Staff Response To Interrogatories 57, 59, 61, 63, 65, 67, 69 and 71:

Interrogatories 57 through 71 all deal with the question of incentives, performance measures and evaluation criteria for judging the success or failure of EARPs:

57. Performance measures and evaluation criteria appropriate for judging success or failure of any past or future EARPs

59. Incentives, if any, created or amplified by the UE EARPs

61. Lack of performance measures and evaluation criteria in the UE EARPs

63. Efficiency measures for evaluating the UE EARPs

65. Rates measures for evaluating the UE EARPs

67. Credits measures for evaluating the UE EARPs

69. Services measures for evaluating the UE EARPs

71. Quality of service measures for evaluating the UE EARPs

Respecting UE Interrogatory 57, Staff does not have adequate information to provide the requested information. The process of establishing an EARP's goal(s) or purpose(s) will determine the appropriate performance measures and evaluation criteria to judge the success or failure of an EARP. The past EARPs

did not specify the expected goal(s) or purpose(s) to be achieved by these programs. Interrogatory 57 and the related definitions do not specify the goal(s) or purpose(s) of any past or future EARP.

The UE EARPs were the result of two negotiated settlements. The first EARP was designed to settle all issues related to Staff's 1994-1995 earnings review of UE. The second EARP was designed to settle all issues related to the UE – CIPSCO merger. The EARPs were successful in this regard as all the issues in Case No. ER-95-411 and Case No. EM-96-149 were settled by the adoption of the EARPS.

Respecting Interrogatory 59, it first should be noted that in the "Definitions" section of UE's First Requests For Admission, UE defines "'incentive' or 'performance-based' ratemaking'" as meaning "ratemaking that incorporates regulatory mechanisms such as pricecaps, rate moratoria, and earnings sharing mechanisms which provide distinctive incentives for more efficient or superior performance not found in traditional cost of service ratemaking." There were no specific or documented incentives created or amplified by the UE EARPs. The EARPs were not designed or intended to be performance or incentive based regulatory experiments. (See Staff response to Interrogatory 58.) As a consequence, Staff insisted that EARP should not include the word "incentive" in its title unlike the preceding telecommunications alternative regulation experiment, the Southwestern Bell Incentive Regulatory Experiment (SBIRE). (March 22, 1995 letter to Donald E. Brandt from Steven Dottheim referred to at page 71 of the June 9, 1999 deposition of Kenneth J. Rademan, Exhibit 40 in Case No. EO-96-14.)

EARP was initially a negotiated settlement resulting from the Staff's 1994-1995 earnings review of UE. EARP was the negotiated compromise that allowed UE ratepayers to receive the rate reduction that ratepayers of UE and other Missouri utilities were traditionally receiving upon the expiration of previous rate moratoriums. EARP also provided UE ratepayers with credits from the excessive rates that were expected to occur while the experiment was in place. These credits were an alternative to the larger permanent rate reduction proposed by the Staff. Among other things, these credits also were in exchange for a longer moratorium than had previously been negotiated by Staff with UE (i.e., 36 months versus 20 to 26 months).

Shortly after the first EARP was approved, UE announced its proposed merger with CIPSCO, Inc. The remainder of the first EARP and the second EARP became the negotiated vehicle to allow UE to retain enough of the savings projected by it from the merger between itself and CIPSCO, Inc. to satisfy itself that the merger would be worthwhile to its shareholders to consummate the transaction. The EARPs were the methodology that would allow UE to retain projected merger savings through the EARP sharing grid and the EARP moratorium on rate decrease complaint cases through June 30, 2001. Commencing July 1, 2001, parties were free to seek a rebasing of UE's rates to its customers commensurate with UE's cost to provide service without the complicating issues of the purported merger premium, merger savings and merger costs of the UE – CIPSCO merger.

Respecting Interrogatory 61 regarding Staff's statement that there is a lack of performance measures and evaluation criteria in the UE EARPs, Staff responds that the bases for its statement are the Commission's Report And Orders in Case No. ER-95-411 (July 21, 1995) (the first EARP) and Case No. EM-96-149 (February 21, 1997) (the second EARP), which include the Stipulation And Agreements entered into in those two cases; the on the record presentations in Case Nos. ER-95-411 and EM-96-149, of which there are transcripts; and the 1996 the Surrebuttal testimony of Donald E. Brandt in Case No. EM-96-149 and statements in various UE pleadings in Case No. EO-96-14 and Case EM-96-149 that Staff's position on monitoring denies UE the benefit of the Stipulation And Agreement in Case No. EM-96-149 regarding recovery of the purported merger premium arising from UE's merger with CIPSCO. These documents reveal no performance measures or evaluation criteria.

However, there were features inherent in the EARPs that would encourage UE to pursue whatever extension of the EARPs it could achieve and then delay any attempt to adjust its rates to reflect its current cost of service. The UE EARPs provided this incentive by permitting higher earnings through the continued charging of excessive rates under the second EARP after its conclusion on June 30, 2001. For example, in the UE EARPs there was not a provision for (1) the continuation of the possibility of sharing credits in the year after the end of the second EARP, while there might be a rate decrease case pending for the rebasing of UE's rates, or (2) a permanent rate reduction after the conclusion of the second EARP based on a three-year average of weather normalized sharing credits, as occurred after the first EARP.

In general in response to this group of UE Interrogatories, Staff notes that performance based or incentive regulation (PBR) can use either external or internal criteria. An example of a PBR with an external criteria is a rate cap that changes automatically with changes in specified external indices. For example, a change in cost of living netted against a change in productivity could be used to make a change in the rate cap. Internal criteria are usually related to specific services. Particularly when quality of service is an objective, measures of consumer satisfaction are used. In other cases, direct measures of services provided can be objectively measured; e.g., levels of reliability. PBR connects rewards/penalties for measured performance relative to a base or normal level. The mere fashioning of a plan with external criteria, internal criteria or a combination of external and internal criteria does not create an acceptable PBR plan. An appropriate PBR plan is grounded on (1) a rebasing of the particular utility's rates and (2) the fashioning of a plan that results in the attainment of a unique level of efficiency not attainable under traditional regulation.

Respecting the lawfulness of an alternative regulation plan, the Commission specifically held in its Report And Order in Case Nos. TC-93-224 and TO-93-192 that once it has reached a decision concerning the utility's revenue requirement, i.e., rebased the utility's rates, (1) it has the statutory authority to adopt a reasonably structured alternative regulation plan, and (2) a utility may voluntarily agree to operate under such a plan. *Re Southwestern Bell Telephone Co.*, Case Nos. TC-93-224 and TO-93-192, Report And Order, 2 Mo.P.S.C.3d 479, 583, 585 (1993).

Although Interrogatories 57, 59, 61, 63, 67, 69 and 71 concern performance measures and evaluation criteria appropriate for judging the success or failure of past or future EARPs, Staff hereafter responds on the basis that performance measures and evaluation criteria are appropriate for judging the success or failure of PBRs. Staff notes again that the UE EARPs were not performance based or incentive regulation.

Regarding Interrogatory 57, the choice of the appropriate performance measures and evaluation criteria depends on the overall objectives of the PBR. For example, external criteria are usually less complex than internal criteria. However, internal criteria are better when specific areas of performance are being targeted. Incentives are determined by the reward/penalties associated with the performance measure. A poorly designed reward/penalty will not provide an incentive to improve performance. A well designed reward/penalty will share the benefits of improved performance with the utility's customers and will attempt to maximize the overall benefits.

Respecting Interrogatory 63 regarding efficiency measures for evaluating the UE EARPs, the efficiency standard for PBRs would be expressed as a quantification of the resources utilized to achieve a specific output. UE's efficiency would likely be measured by the change in the relationship of the cost to provide service in relation to the amount and quality of service provided. A measure of efficiency would need to be chosen and UE's performance determined at the levels that existed prior to the implementation of the regulatory experiment.

Interrogatories 63 through 72 deal with specific items (efficiency, rates, credits, services and quality of service) that may or may not be included in a specific PBR. An item from the list of performance criteria being measured for a possible PBR reward/penalty would be measured via a performance indicator and benchmarked with respect to functions that could impact these items. The benchmarks would establish the levels that existed prior to the implementation of the PBR.

Historical information would be the starting point in the development of these performance measures and benchmarks. Historical information would be evaluated to determine the need for adjustments to reflect items such as installation of new systems or aberrations in past data that are not reflective of normal conditions.

At the very outset, discussion would be conducted to determine whether the PBR would be intended and designed to have either a positive or no impact on the items on the list of performance criteria. It is assumed that no PBR would be approved that was thought might negatively impact an item on the list of performance criteria, however there may be certain PBRs approved that recognize a trade-off between items on the list; e.g., improved services or quality of service may result in higher rates:

1. If it was desired or expected that the PBR will have a positive impact on an item on the list, then measures and rewards/penalties related to the

performance measures would need to be specified (see responses to Interrogatory 57 and Interrogatory 59).

2. If it was desired or expected that the PBR experiment not specifically impact an item on the list (e.g., an external PBR that focuses on overall rate of return), then measures of current acceptable performance and benchmarks would need to be established and monitored to determine whether the PBR has no detrimental impact on the item.

After performance indicators and benchmarks are established, they would be evaluated for possible impacts from external factors during the term of the experiment.

In response to Interrogatory 63, Staff states the efficiency standard would be expressed as a quantification of the resource utilized to achieve a specific output. UE's efficiency would likely be measured by the change in the relationship of the cost to provide service in relation to the level and quality of service provided. While historical levels of efficiency can sometimes provide a proper basis for a benchmark from which to measure change, there can be problems with measurements related to both service quality and costs. For example, if efficiency measures do not include quality measures, costs can be reduced simply by lowering quality. Alternatively, costs may increase from external factors (e.g., floods) that are beyond the utility's control, and simply comparing unit costs to a base year may be a poor measure of efficiency.

In response to Interrogatory 65, Staff relates that the standard addressed in this Interrogatory is the expected impact of the EARPs on rates during the life of the EARPs. The expectations are contained in the EARP Stipulation And Agreements. The measurement of that standard would be what turned out to be under the second EARP an approximate $16 million permanent rate reduction after the expiration of the three-year term of the first EARP, pursuant to a provision of the Stipulation And Agreement in Case No. EM-96-149. The terms of the second EARP Stipulation And Agreement which resulted in the approximate $16 million permanent rate reduction after the third year of the first EARP provided for a permanent rate reduction based on a three-year average of any weather-normalized customer credits occurring during the three years of the first EARP. There were customer credits each of the three years of the first EARP. The three-year average of the weather-normalized customer credits amounted to approximately $16 million (part of the possible amount of this rate reduction is still on review before the Circuit Court of Cole County). This item in the second EARP was the only expected rate change contemplated by either of the two EARPs. Staff did not prepare an estimate of the amount of the rate reduction to occur after the first EARP's three-year term. The EARP rate moratoriums precluded any other rate changes during life of the EARPs. There were events covered in the provisions of the two Stipulation And Agreements which, had they occurred, would have made it possible for UE to terminate either of the two EARPs, short of each EARP's three year duration.

The initial $30 million permanent rate reduction of the first EARP was a negotiated amount which was part of the establishment of the first EARP in Case No. ER-95-411. That amount was the result of the Staff's audit of UE's rates at that time. The $30 million permanent rate reduction was not the result of UE operating under the EARPs, but was a condition of the Staff entering into the second EARP.

In response to Interrogatory 67, Staff states the standard addressed in this Interrogatory is the expected amount of EARP credits to consumers during the life of the EARP. Customer credits impacts the price that consumers ultimately pay for service. The basis for these expectations is contained in the EARP Stipulation And Agreements. Staff did not estimate the amount of credits that would be expected either annually or in total over the lives of the EARPs. The actual measurement of the credits would be the cumulative amount of the final customer credit for the individual year of the EARPs. The final customer credit for each individual year of the EARPs would not be counted in any subsequent year of the EARPs.

The amount of credits generated for each year of the first EARP is contained in the February 10, 2000 Staff Response To Commission Orders Of December 12, 1999 And January 20, 2000 in Case No. EO-96-14. The amount of the credits generated in the first and second years of the second EARP is set out in the Stipulation And Agreements filed in Case No. EM-96-149 for the years July 1, 1998 to June 30, 1999 and July 1, 1999 to June 30, 2000.

In response to Interrogatory 69, Staff comments that "services" refers to either the level of existing services or to new services, and in response to Interrogatory 71, Staff notes that "quality of service" applies to consumer perception of the services. An example may help to explain. Consider an internal performance criterion: the number of minutes after electric service is interrupted before it is restored. The fact that it is being measured might be new, or if a target level is being set, that might be new, but the restoration of

electric service after a service interruption has always been a utility service to customers. The time to restoration can either be considered a level of the service or a measure of the quality of service. The intent of the use of the words "services and quality of service," on page 8 of the Staff's February 1, 2001 Report, was to cover all aspects of the provision of service.

58. Identify each document that you rely on, that forms the basis of, or that otherwise supports your answer to the preceding Interrogatory.

60. Identify each document that you rely on, that forms the basis of, or that otherwise supports your answer to the preceding Interrogatory.

62. Identify each document that you rely on, that forms the basis of, or that otherwise supports your answer to the preceding Interrogatory.

64. Identify each document that you rely on, that forms the basis of, or that otherwise supports your answer to the preceding Interrogatory.

66. Identify each document that you rely on, that forms the basis of, or that otherwise supports your answer to the preceding Interrogatory.

68. Identify each document that you rely on, that forms the basis of, or that otherwise supports your answer to the preceding Interrogatory.

70. Identify each document that you rely on, that forms the basis of, or that otherwise supports your answer to the preceding Interrogatory.

72. Identify each document that you rely on, that forms the basis of, or that otherwise supports your answer to the preceding Interrogatory.

<u>Staff Response to Interrogatories 58, 60, 62, 64, 66, 68, 70, and 72</u>: **The documents relied on, that form the basis of, or that otherwise support the**

***answers to the* <u>*Interrogatories 58 through 72*</u> *are identified in the response to* <u>Interrogatories 57 through 71</u>.**

73. On page 11 of the Staff's EARP Report, you contend: "[T]he ROE grid for sharing is set at a level which has resulted in UE receiving, through customer rates, revenues which are clearly excessive even after sharing . . . ."

a. Explain in as much detail as you can the basis for this contention.

<u>Staff Response</u>: **The basis for this contention is contained on page 27 of the Staff's February 1, 2001 EARP Report Regarding The Experimental Alternative Regulation Plans Of Union Electric Company, D/B/A AmerenUE in Case No. EM-96-149. Also see Staff's response to Admission Request 33 of UE's First Set Of Requests For Admission.**

b. Identify each document that you rely on, that forms the basis of, or that otherwise supports this contention.

<u>Staff Response</u>: **Staff's February 1, 2001 Report Regarding The Experimental Alternative Regulation Plans Of Union Electric Company, D/B/A AmerenUE in Case No. EM-96-149, and the revenue requirement runs and related workpapers supporting page 27 of Staff's February 1, 2001 Report and the filing on February 10, 2000, in Case No. EO-96-14, of the Staff Response To Commission Orders Of December 23, 1999 And January 20, 2000.**

c. When did you become aware of these "clearly excessive" revenues referred to in this contention?

<u>Staff Response</u>: **The actual quantification that measured the extent of the clearly excessive revenues occurred prior to the filing of Staff's February 1, 2001 Report**

Regarding The Experimental Alternative Regulation Plans Of Union Electric Company, D/B/A AmerenUE in Case No. EM-96-149. Staff was aware that Union Electric had excessive revenues of approximately $100 million annually prior to filing the Staff Response To Commission Orders Of December 23, 1999 And January 20, 2000 on February 10, 2000, in Case No. EO-96-14.

Staff also would note a dialogue between Commissioner David L. Rauch and undersigned counsel at the on the record presentation respecting the Stipulation And Agreement in Case No. ER-93-52, whereby undersigned counsel stated the Staff's approach to settlement of rate decrease cases, i.e., cases where a utility has clearly excessive revenues. In Case No. ER-93-52, UE agreed to permanently reduce its rates by $40 million commencing January 1, 1993. Staff mentioned at the on the record presentation that, from the Staff's perspective, the $40 million was associated with the end of the amortization of the deferral of the costs relating to the phase-in of the Callaway nuclear generating unit. In response to questions from Commissioner Rauch, undersigned counsel stated further as follows:

MR. DOTTHEIM:

. . . .

> The other thing, I guess, I maybe should state is that it is not the Staff's policy, either with Union Electric Company or other companies, where earnings investigations occur, where audits are performed, and in instances when the Staff makes a determination that a company may be in an excess earnings situation
> It is not the Staff's policy to be – some would argue could it be so precise as to eliminate, through a complaint case, all purported excess earnings. The Staff, if it could, would not likely endeavor to do that for fear of adverse events occurring immediately after the complaint case which might force the

> **company to immediately thereafter file a rate increase case. So *that is another factor that goes into the Staff's consideration in* negotiating settlements involving matters such as this.**
>
> **COMMISSIONER RAUCH: So you're almost building a buffer?**
>
> **MR. DOTTHEIM: Yes.**
>
> **COMMISSIONER RAUCH: In case of adverse situations.**
>
> **MR. DOTTHEIM: That's not to say that we can pinpoint precisely the size of that buffer. But that is part of the thought process on behalf of the Staff.**

(Transcript of the October 8, 1992 on the record presentation, pages 28-29, Case No. ER-93-52).

d. What analysis did you undertake, and at what time, that made you aware of these "clearly excessive" revenues referred to in this contention?

Staff Response: Staff prepared a revenue requirement analysis of each of the years under the first EARP and the first year under the second EARP. This analysis was preformed in preparation for the Staff's February 1, 2001 Report Regarding The Experimental Alternative Regulation Plans of Union Electric Company, D/B/A AmerenUE in Case No. EM-96-149.

e. *Identify `each document that you reviewed or considered as part of the analysis by* which you became aware of these "clearly excessive" revenues referred to in this contention.

Staff Response: The revenue requirement runs and related workpapers supporting page 27 of Staff's February 1, 2001 Report Regarding The Experimental Alternative Regulation Plans of Union Electric Company, D/B/A AmerenUE in Case No. EM-96-149.

f. Identify each person who participated in any way in the analysis by which you became aware of these "clearly excessive" revenues referred to in this contention.

<u>Staff Response</u>: **Steve Rackers, Ron Bible, and Greg Meyer.**

g. Explain in as much detail as you can what you contend are the objective criteria by which to determine whether a utility's revenues are "excessive."

<u>Staff Response</u>: **The objective criteria by which one can determine whether a utility's revenues are excessive are the comparison of (1) the revenues generated by current rates applied to the appropriate sales volumes to (2) the company's cost to provide service. In the event that that the company's revenues generated by current rates applied to the appropriate sales volume exceeds the company's cost to provide service, then the utility's revenues are excessive.**

h. Identify each document that you rely on, that forms the basis of, or that otherwise supports your contention of what are the objective criteria by which to determine whether a utility's revenues are "excessive."

<u>Staff Response</u>: **See Schedule 28 attached to the Direct Testimony of Ron Bible in Case No. EC-2002-1 and *Re Union Electric Co.*, Case Nos. 18,314 and 18,527, 20 Mo.P.S.C.(N.S.) 395, 400-01 (1975).**

74. On page 11 of the Staff's EARP Report, you contend: "[T]he disputes between UE and the Staff and OPC concerning how the EARPs are supposed to operate, have resulted in protracted litigation and delays in customers receiving the intended benefits of the operation of the EARPs."

a. Explain in as much detail as you can the basis for this contention.

Staff Response: The Staff generally viewed the EARP as a streamlined mechanism to provide to ratepayers excessive revenues associated with cost of service over a shorter time frame than would occur under traditional regulation. The credits from the first sharing period of the first EARP were returned within the anticipated time frame. However, the credit process for each of the subsequent sharing periods has been delayed. The credit sharing process for the third sharing period of the first EARP, which ended 6/30/98, was delayed until 2000, and even now it has not been completed. The third year process included depositions, hearings before the Commission, and UE seeking judicial review and a stay. The case is pending in Circuit Court.

b. Identify each document that you rely on, that forms the basis of, or that otherwise supports this contention.

Staff Response: The documents relied on, that form the basis of, or that otherwise support this contention are the pleadings, testimony, transcripts and exhibits in Case No. EO-96-14 and Case No. EM-96-149, respecting the proceedings concerning each year's sharing credits, the pleadings and record in the Circuit Court of Cole County in Case Nos. 00CV323273 and 00CV323608, and the record in Case No. TO-90-1.

c. Explain in as much detail as you can the standard by which you contend that "disputes . . . concerning how the EARPs are supposed to operate, have resulted in protracted litigation."

Staff Response: The standard was the Staff's experience in Case No. TO-90-1, the Southwestern Bell Incentive Regulatory Experiment (SBIRE), where none of the four years of sharing credits was contested before the Commission.

d. Identify each document that you rely on, that forms the basis of, or that otherwise supports this contention.

Staff Response: The documents relied on, that form the basis of, or that otherwise support this contention are the pleadings, testimony, transcripts and exhibits in Case No. EO-96-14 and Case No. EM-96-149, respecting the proceedings concerning each year's sharing credits, the pleadings and record in the Circuit Court of Cole County in Case Nos. 00CV323273 and 00CV323608, and the record in Case No. TO-90-1.

e. Explain in as much detail as you can what you mean by "protracted litigation."

Staff Response: "Protracted litigation" means litigation over an extended or long period of time.

f. Identify each document that you rely on, that forms the basis of, or that otherwise supports what you mean by "protracted litigation."

Staff Response: The documentation referred to above in the Staff response to this Interrogatory.

75. Describe all the "expense savings, particularly in fuel and other generation costs as well as savings resulting from overall employee reductions," you contend UE would have achieved without the EARPs.

Staff Response: The Staff has not performed a detailed analysis to provide a specific listing of expense savings events related to the above statement.

However, the Staff is aware of a UE employee reduction program, the Targeted Separation Plan, that occurred during the EARPs. The Staff is unable to determine if that employee reduction program was the result of the EARPs.

a. Explain in as much detail as you can the basis for this contention.

Staff Response: EARP was not designed or intended to be a performance or incentive based regulatory experiment. See Staff response to Interrogatory 61. As a consequence, Staff insisted that EARP should not include the word "incentive" in its title unlike the preceding telecommunications alternative regulation experiment, the Southwestern Bell Incentive Regulatory Experiment (SBIRE). (March 22, 1995 letter to Donald E. Brandt from Steven Dottheim referred to at page 71 of the June 9, 1999 deposition of Kenneth J. Rademan, Exhibit 40 in Case No. EO-96-14.)

EARP was initially a negotiated settlement resulting from the Staff's 1994-1995 earnings review of UE. EARP was the negotiated compromise that allowed UE ratepayers to receive the rate reduction that ratepayers of UE and other Missouri utilities were traditionally receiving upon the expiration of previous rate moratoriums. EARP also provided UE ratepayers credits from the excessive rates that were expected to occur while the experiment was in place. These credits were an alternative to the larger permanent rate reduction proposed by the Staff. Among other things, these credits also were in exchange for a longer moratorium than had previously been negotiated by Staff with UE (i.e., 36 months versus 20 to 26 months).

Shortly after the first EARP was approved, UE announced its proposed merger with CIPSCO, Inc. The remainder of the first EARP and the second EARP became the negotiated vehicle to allow UE to retain enough of the savings projected by it from the merger between itself and CIPSCO, Inc. to satisfy itself that the merger would be worthwhile to its shareholders to consummate the transaction. The EARPs were the methodology that would allow UE to retain projected merger savings with its sharing grid through June 30, 2001. At that time, parties were free to seek a rebasing of UE's rates to its customers commensurate with UE's cost to provide service without the complicating issues of the purported merger premium, merger savings and merger costs.

Another basis for this contention is that UE deemed cost reductions as a vital component of its business strategy significantly before the adoption of the first EARP. This fact can be shown by the Direct Testimony of Gary L. Rainwater, dated November 2, 1995, filed in Case No. EM-96-149, pages 8-9, where Mr. Rainwater testified, in part, that:

> Cost reduction has been a key element in UE's business strategy for the past ten years. As a result of aggressive cost reductions, our Callaway rate phase-in plan was terminated in 1987, thereby avoiding scheduled electric rate increases totaling $189 million that would have occurred in 1988, 1989, and 1990. Through continued cost reductions, our electric rates have been reduced by an additional $100 million: by $30 million per year in 1990, $40 million per year in 1993, and another $30 million per year in 1995.

Mr. Rainwater further testified at page 9 that there were three reasons why cost reductions are so important to UE. The first reason he provided was that

"[w]e [i.e., UE] have a basic obligation to our customers to operate as efficiently as possible."

There is no expense reduction at UE that is unique to the electric industry or UE within the electric industry.

b. Identify each document that you rely on, that forms the basis of, or that otherwise supports this contention.

Staff Response: **Direct Testimony of Gary L. Rainwater in Case No. EM-96-149, dated November 2, 1995, pages 8-9; the Commission's Report And Orders in Case No. ER-95-411 (July 21, 1995) and Case No. EM-96-149 (February 21, 1997), which include the Stipulation And Agreements entered into in those two cases; the September 5, 1996 on-the-record presentation of the Stipulation And Agreement in Case No. EM-96-149, pages 19, 28, 29, and 106; and the Surrebuttal Testimony of Donald E. Brandt in Case No. EM-96-149, dated June 3, 1996, pages 3-6.**

76. What do you contend are the objective criteria by which the riskiness of a utility should be measured or evaluated for ratemaking purposes?

Staff Response: **Staff does not have a specific list of objective criteria by which the riskiness of a utility should be measured or evaluated for ratemaking purposes.**

a. *Explain in as much detail as you can the basis for this contention.*

Staff Response: **There are several sources of information that are of benefit in assessing the relative riskiness of a utility. None of these sources alone would give a fair representation of the relative riskiness of a utility. Rather, the information**

as a whole should be evaluated to assess the relative riskiness of a utility. These information sources can include: credit ratings, credit reports, investor perceptions, investment advisory reports, investment analyst reports, company annual reports, beta, standard deviation, variance and covariance.

b. Identify each document that you rely on, that forms the basis of, or that otherwise supports this contention.

Staff Response: **Staff's response is based on its knowledge and experience. Staff did not rely on any specific document to formulate its response to this statement.**

77. Based on the objective criteria noted in the preceding Interrogatory, do you contend that AmerenUE is as risky as, less risky, or more risky than Ameren?

Staff Response: **Staff makes no contention that AmerenUE is less, the same or more risky than Ameren.**

a. Explain in as much detail as you can the basis for this contention.

Staff Response: **Staff has not performed any analysis or research upon which to base such a contention. Staff's experience has not provided a definitive basis to make the requested contention.**

b. Identify each document that you rely on, that forms the basis of, or that otherwise supports this contention.

Staff Response: **Staff did not rely on any specific document to formulate its response to the requested contention.**

78. Based on the objective criteria noted in the preceding Interrogatory, do you contend that the electric utility operations of AmerenUE are as risky as, less risky, or riskier than the natural gas operations of AmerenUE?

Staff Response: **Staff makes no contention that electric utility operations of AmerenUE are less, the same or more risky than the natural gas operations of AmerenUE.**

a. Explain in as much detail as you can the basis for this contention.

Staff Response: **Staff has not performed any analysis or research upon which to base such a contention. Staff's experience has not provided a definitive basis to make the requested contention.**

b. *Identify each document that you rely on, that forms the basis of, or that otherwise* supports this contention.

Staff Response: **Staff did not rely on any specific document to formulate its response to the requested contention.**

79. Explain in as much detail as you can the basis for Mr. Bible's sole reliance on the *DCF results of the parent of the regulated company to estimate costs of equity.*

Staff Response: **The DCF model is one of the oldest and most commonly used models for estimating cost of equity.** ***The Cost Of Capital – A Practitioner's Guide*****, Parcell, 1997, indicates the DCF model is the model favored by federal and state regulatory agencies. The DCF model gives the most reliable estimate of cost of equity. The DCF model has been relied on historically by the Missouri Public Service Commission and is, therefore, a part of its regulatory practice. The DCF model is the only model in use with all of the inputs unique to the company being studied.**

80. Identify each document that you rely on, that forms the basis of, or that otherwise *supports your answer to the preceding Interrogatory.*

Staff Response: See Staff Response to Interrogatory No. 79 above. Past Commission cases and precedent indicate that it has been a long-standing practice of this Commission to rely on the results of the DCF for an estimation of the cost of equity capital. In *Re St. Louis County Water Co.*, Case No. WR-2000-844, Report And Order, pp. 25-27 (May 3, 2001), the Commission stated as follows:

> . . . The Commission has for many years judged the DCF method to be the most reliable for calculating a utility's cost of equity:
>
>> The Commission has consistently found Discounted Cash Flow (DCF) analyses to be appropriate for determining a rate of return on equity. . . . This is because it is relatively simple to apply and measures investor expectations for a specific company. . . . [T]he DCF analysis is considerably more systematic and allows this Commission to treat all utilities it regulates in a consistent manner.[7]
>
> [7] In the Matter of the Joint Application of Missouri Cities Water Company, 26 Mo.P.S.C.(N.S.) 1, 26-27 (1983).

81. With respect to Schedules 11 and 22 to Mr. Bible's testimony, explain in as much detail as you can why compound growth rates of Dividend Per Share (DPS), Earnings Per Share (EPS), and Book Value Per Share (BVPS) are used, instead of the arithmetic average of growth rates, in calculating the historical growth rates.

Staff Response: Staff is aware that compound and arithmetic averages are in use. Compound growth more accurately depicts growth or changes over more than one period of time. It is Staff's experience that compound average is the most prevalent method for this calculation. A mathematical example will demonstrate the reliability of compound over arithmetic average. Example: a company pays $1.00 dividend in year one. It pays $1.50 dividend in year two,

plus 50 percent growth. It pays $.75 dividend in year three, negative 50 percent growth. The arithmetic average of plus 50 percent and negative 50 percent is zero. However, the dividend went from $1.00 to $.75. The arithmetic average is zero percent, while the compound average is negative 13.4 percent. Clearly, compound average is a superior representation of the growth over these periods.

82. Identify each document that you rely on, that forms the basis of, or that otherwise supports your answer to the preceding Interrogatory.

<u>Staff Response</u>: **See reference in Staff Response to Interrogatory No. 81. Also, most any textbook dealing with numerical changes over time support compound growth. It is considered common knowledge. Staff's experience has been that investment advisory services, such as Value Line, quote compound growth rates. Also, compound growth is the preferred method used in reference sources, such as textbooks and published articles. Examples of the use of compound growth can be found in *Regulatory Finance, Utilities' Cost of Capital*, Roger A. Morin, 1994 and *The Cost Of Capital – A Practitioner's Guide*, Parcell, 1997.**

83. Do you contend that the use of arithmetic average (as opposed to compound average) growth rates is inappropriate in calculating the historical average of DPS, EPS, and BVPS growth?

<u>Staff Response</u>: Yes.

a. If so, explain in as much detail as you can the basis for this contention.

<u>Staff Response</u>: **Staff is aware that compound and arithmetic averages are in use. Compound growth more accurately depicts growth or changes over more than one period of time. It is Staff's experience that compound average is the**

most prevalent method for this calculation. A mathematical example will demonstrate the reliability of compound over arithmetic average. Example: a company pays $1.00 dividend in year one. It pays $1.50 dividend in year two, plus 50 percent growth. It pays $.75 dividend in year three, negative 50 percent growth. The arithmetic average of plus 50 percent and negative 50 percent is zero. However, the dividend went from $1.00 to $.75. The arithmetic average is zero percent, while the compound average is negative 13.4 percent. Clearly, compound average is a superior representation of the growth over these periods.

a. If so, identify each document that you rely on, that forms the basis of, or that otherwise supports this contention.

Staff Response: **See reference in Staff Response to Interrogatory No. 81. Also, most any textbook dealing with numerical changes over time support compound growth. It is considered common knowledge. Staff's experience has been that investment advisory services, such as Value Line, quote compound growth rates. Also, compound growth is the preferred method used in reference sources, such as textbooks and published articles. Examples of the use of compound growth can be found in *Regulatory Finance, Utilities' Cost of Capital*, Roger A. Morin, 1994 and *The Cost Of Capital – A Practitioner's Guide*, Parcell, 1997.**

84. Do you contend that it is unreasonable or inappropriate to calculate expected dividends as $D_1 = D_0 * (1+g)$ or $D_1 = D_0 * (1+0.5g)$?

Staff Response: **Yes.**

a. If so, explain in as much detail as you can the basis for this contention.

Staff Response: Staff contends that D_1, as it is used in the DCF model, is the anticipated or expected dividend. In the absence of any indication by the company of its intention to increase its dividend and the amount of that increase, using D_0 * (1+g), or D_0 * (1+.5g) to represent D_1 is arbitrary and inaccurate. For example, Ameren has not increased its dividend for more than two years. Staff is not aware of any intention by Ameren's management or board of directors to increase its dividend. Therefore, to assume that Ameren will increase its current dividend by g or .5g is arbitrary and inaccurate.

b. If so, identify each document that you rely on, that forms the basis of, or that otherwise supports this contention.

Staff Response: Staff did not rely on any specific document to formulate its response to this statement.

85. With respect to Schedules 13 and 14 to Mr. Bible's testimony, explain in as much detail as you can the justification for using Value Line dividend forecasts as the expected dividends.

Staff Response: Value Line provides financial information generally recognized and relied upon by investors for information respecting the companies covered. Value Line's results are consistent with what Staff has observed.

86. Identify all sources of information regarding dividend forecasts, other than Value Line, that are appropriate to use in the DCF model.

Staff Response: Staff has not done exhaustive research into all potential sources of dividend forecasts that may be appropriate to use in the DCF model. Potential sources of dividend forecasts for a particular company would be unique to the

entity being studied. For example, not all sources of dividend forecasts would necessarily develop a forecast of dividends for the company in question.

87. Identify each document that you rely on, that forms the basis of, or that otherwise supports your answer to the preceding Interrogatory.

<u>Staff Response</u>: **Staff did not rely on any specific document to formulate its response to this statement. Value Line provides financial information generally recognized and relied upon by investors for information respecting the companies covered. Value Line's results are consistent with what Staff has observed.**

88. Identify all documents any member of the Staff has written analyzing, considering, or in any way discussing the data supplied by AmerenUE in its monthly reports pursuant to 4CSR 240-20.080.

<u>Staff Response</u>: **Staff analysis of the 20.080 data is included in the context of the response to the request for production of documents, item #7.**

<u>Prepared by</u>: **John Cassidy**

<u>Staff Response</u>: **Anne Ross is providing four groups of production, they are as follows:**

I. Provided: Response re. documents used to develop price comparisons pertaining to Purchases and Sales of Electricity.

Corresponding files requested per Union Electric Company's First Set of Requests for Production of Documents: These files are on CD, in a folder titled Files Used in Purchase & Sales Price Comparison — Anne Ross.

Note: When used with respect to a document, "identify" means (i) state the name, address, and telephone number of its author or maker; (ii) state the names, addresses, and telephone numbers of all persons who were addressees of the document or who otherwise reviewed it; (iii) state the date of the document; (iv) state the title of the document and any other identifying characteristic of the document, including any serial, reference, or file number; (v) describe the type or format of the document (e.g., letter, memorandum, transcript, computer program); (vi) briefly describe the substance of the information or communication set forth in the document; and (vii) in the event any such document was but is no longer in your possession, custody or control, describe what disposition was made of the document and when and where the document may now be found.

(i) Anne Ross

(ii) Used by Anne Ross

(iii) June 2001

(iv) The folder Files Used in Purchase & Sales Price Comparison — Anne Ross contains subfolders entitled Purchases - 1999, Sales — 1999, Purchases – 2000, and Sales — 2000. These subfolders contain the monthly files in which I calculated spot sales and spot purchase prices using the 20.080 data and the first 2 PowerPrice macros.

(v) EXCEL files

(vi) These files were used to create the prices used in the price comparisons that I supplied to Dr. Mike Proctor.

(vii) n/a

II. Provided: Response re. documents provided to Leon Bender pertaining to Purchases of Electricity. Email correspondence on this matter. Corresponding files requested per Union Electric Company's First Set of Requests for Production of Documents: These files are on CD, in a folder titled Files Sent to Leon Bender — Anne Ross.

Note: When used with respect to a document, "identify" means (i) state the name, address, and telephone number of its author or maker; (ii) state the names, addresses, and telephone numbers of all persons who were addressees of the document or who otherwise reviewed it; (iii) state the date of the document; (iv) state the title of the document and any other identifying characteristic of the document, including any serial, reference, or file number; (v) describe the type or format of the document (e.g., letter, memorandum, transcript, computer program); (vi) briefly describe the substance of the information or communication set forth in the document; and (vii) in the event any such document was but is no longer in your possession, custody or control, describe what disposition was made of the document and when and where the document may now be found.

Purchases of Electricity

(i) Anne Ross

(ii) Leon Bender

(iii) June 15-18, 2001

(iv) These files may be found on CD in the Files Sent to Leon Bender — Anne Ross folder, in the following subfolders:

Correct PP files sent to Leon Bender June 18, 2001

Correct Realtime Input and @Riskfiles sent to Leon Bender June 18, 2001

Incorrect PP files sent to Leon Bender June 15, 2001

Incorrect Realtime Input file sent to Leon Bender June 15, 2001

(v) EXCEL files.

(vi) Correct PP files sent to Leon Bender June 18, 2001 — contains files created using AmerenUE's 4 CSR 240-20.080, Section (1)(D) spot purchase data and PowerPrice macros.

Correct Realtime Input and @Risk files sent to Leon Bender June 18, 2001 — contains files created using AmerenUE's 4 CSR 240-20.080, Section (1)(D) spot purchase data and @Risk program.

Incorrect PP files sent to Leon Bender June 15, 2001 — contains original (incorrect, not used) files created using AmerenUE's 4 CSR 240-20.080, Section (1)(D) spot purchase data and PowerPrice macros.

Incorrect Realtime Input file sent to Leon Bender June 15, 2001 — contains original (incorrect, not used) files created using AmerenUE's 4 CSR 240-20.080, Section (1)(D) spot purchase data and @Risk program.

(vii) n/a

III. Provided: Response re. documents provided to Lena Mantle pertaining to Net System Load. Email correspondence on this matter.

Corresponding files requested per Union Electric Company's First Set of Requests for Production of Documents: These files are on CD, in a folder titled Files Sent to Lena Mantle — Anne Ross .

Note: When used with respect to a document, "identify" means (i) state the name, address, and telephone number of its author or maker; (ii) state the names, addresses, and telephone numbers of all persons who were addressees of the document or who otherwise reviewed it; (iii) state the date of the document; (iv) state the title of the document and any other identifying characteristic of the document, including any serial, reference, or file number; (v) describe the type or format of the document (e.g., letter, memorandum, transcript, computer program); (vi) briefly describe the substance of the information or communication set forth in the document; and (vii) in the event any such document was but is no longer in your possession, custody or control, describe what disposition was made of the document and when and where the document may now be found.

Net System Load

Using the data supplied by AmerenUE under 4 CSR 240-20.080, Section 1C, I extracted hourly loads for AmerenUE, CIPS, and Union Electric. This information was supplied to Lena Mantle.

(i) Anne Ross

(ii) Lena Mantle

(iii) Approximately April, 2001 — July, 2001

(iv) These files may be found on CD, in the Files Sent to Lena Mantle — Anne Ross folder: Ameren 1999, Ameren 2000, Ameren 2001

(v) EXCEL files

(vi) These computer files contain Hourly Loads of CIPS, Ameren, and Union Electric. These loads were extracted from Ameren's 4 CSR 240-20.080 filings, section 1C.

(vii) n/a

IV. Provided: Response re. documents provided to Mike Proctor pertaining to Purchases and Sales of Electricity.

Corresponding files requested per Union Electric Company's First Set of Requests for Production of Documents: These files are on CD, in a folder titled Files Sent to Mike Proctor — Anne Ross.

Note: When used with respect to a document, "identify" means (i) state the name, address, and telephone number of its author or maker; (ii) state the names, addresses, and telephone numbers of all persons who were addressees of the document or who otherwise reviewed it; (iii) state the date of the document; (iv) state the title of the document and any other identifying characteristic of the document, including any serial, reference, or file number; (v) describe the type or format of the document (e.g., letter, memorandum, transcript, computer program); (vi) briefly describe the substance of the information or communication set forth in the document; and (vii) in the event any such document was but is no longer in your possession, custody or control, describe

what disposition was made of the document and when and where the document may now be found.

(i) Anne Ross

(ii) Dr. Michael S. Proctor

(iii) June 25, 2001

(iv) The files may be found on CD in the folder Files Sent to Mike Proctor — Anne Ross. This folder contains the following files:

1999 Purchases & Sales Prices.xls, 2000 Purchases & Sales Prices.xls, 2000 Purchases — Sales Prices.xls

(v) EXCEL files

(vi) These files contain graphical comparisons of the spot purchase and spot sales prices obtained by running AmerenUE's 4 CSR 240-20.080 1D Purchases and Sales data through the first 2 PowerPrice macros.

(vii) n/a

Prepared by: **Anne Ross**

89. On page 3 (lines 2-3) of the testimony of Leon C. Bender, Mr. Bender makes the following statement: "The RealTime production cost model . . . is the same model used by Staff in all other electric rate cases since 1995."

a. Explain in as much detail as you can the basis for this statement.

Staff Response: **The RealTime production cost model was purchased in 1995. In rate cases when a production cost model has been run, RealTime has been used since that time.**

Prepared by: **Leon Bender**

b. Identify each rate case in which this model was used.

Staff Response: **EC-2002-1 AmerenUE Complaint Case, ER-2001-299 Empire District Electric (EDE) Rate Case, ER-99-247 St. Joseph Light and Power Rate Case, ER-97-394 UtiliCorp United Inc. Rate Case, EC-97-362 UtiliCorp United Inc. Complaint Case, ER-97-82 EDE Interim Rate Case, ER-97-81 EDE Rate Case and ER-95-279 EDE Rate Case.**

Prepared by: **Leon Bender**

90. The term "net purchased power" is used by Leon C. Bender on page 2 (line 10) of his testimony.

a. Explain in as much detail as you can the meaning you give to this term.

Staff Response: **"Net purchased power" as used in this case is the purchased power to meet the weather-normalized load used in the production cost model. The value includes only the cost of the energy purchased and thus is net of any capacity charges or other fees.**

Prepared by: **Leon Bender**

b. Describe the input data associated with this term.

Staff Response: **The input data used in this term is described in the direct testimony of Leon Bender and is provided in his work papers.**

Prepared by: **Leon Bender**

c. Identify the production cost results associated with this term.

Staff Response: **The production cost results related with this term is labeled "Purchases" on the model results output sheets.**

Prepared by: **Leon Bender**

91. The term "net power purchases" is used on page 2 (line 18) of the testimony of Leon C. Bender.

a. Explain in as much detail as you can the meaning you give to this term.

b. Describe the input data associated with this term.

c. Identify the production cost results associated with this term.

Staff Response: **The term "net power purchases" is synonymous with "net purchased power" as described in question 90 and is discussed in that question.**

Prepared by: **Leon Bender**

92. On page 6 (lines 5-6) of the testimony of Leon C. Bender, to "determine the price of emergency purchased energy available," Mr. Bender states he "used the highest price actually paid for purchased power in a given month plus 10%."

a. Explain in as much detail as you can the basis for this method of determining the price of emergency purchased energy.

Staff Response: **It is recognized by Staff that some energy may have to be purchased when generation and other forms of contract and spot energy suddenly become unavailable. Because of the immediate need and the short term involved it is expected the utility will have to pay the highest price to obtain this energy. As stated in testimony Staff used the highest price actually paid, based upon 20.080 data, plus 10%. The 10% was added because frequently in contracts the utility can obtain energy up to the maximum amount from the supplier for the supplier's cost plus some markup, typically ten percent.**

Prepared by: **Leon Bender**

b. Identify each document upon which Mr. Bender relied in choosing this method, or which in any way supports Mr. Bender's use of this method.

<u>Staff Response</u>: **Because the market is unpredictable, it was decided to use actual prices paid based upon 20.080 data. This method was chosen because it represents actual historical data supplied by the Company. The Company already has this data and it is supplied again in the work papers.**

<u>Prepared by</u>: **Leon Bender**

93. Explain in as much detail as possible how the "normalized cost of fuel and net purchased power" that is presented in the testimony of Leon C. Bender is used in your accounting schedules and related work papers.

<u>Staff Response</u>: **The Company's per book levels of fuel and net purchased power of $336,938,875 are included in Staff Accounting Schedule 9, under Operation and Expense categories of Production Expense. The Staffs normalized cost of fuel and net purchased power level of $343,785,940 is allocated to a Missouri level of $298,853,109 ($343,785,940 times 86.93%). This $298,853,109 level is adjusted against Missouri allocated test year per book levels of fuel and the net purchased power level of $292,900,964 ($336,938,875 times 86.93%) which results in Staffs adjustment S-10.2 of $5,952,145.**

<u>Prepared by</u>: **John Cassidy**

94. On page 4 (lines 4-5) of the testimony of Lena M. Mantle, Ms. Mantle states the following: "To get the data to meet the requirements of the production costing model, I had to remove station use from both UE and Ameren loads. . ."

a. Explain in as much detail as you can the basis for this statement.

Staff Response: Station use is dependent upon the generation necessary to meet the load. To weather normalize the loads that include station use (gross load) would be to assume that the same generation units would run given normal weather and that station use has the same weather sensitivity as the total customer usage. Also see page 4 (lines 13 – 19) of the testimony of Lena M. Mantle.

Prepared by: Lena M. Mantle

b. Identify each document that you rely on to make this statement, or otherwise supports the basis for this statement.

Staff Response: None

Prepared by: Lena M. Mantle

c. Describe how the production cost associated with station use is reflected in your cost of service analysis.

Staff Response: The heat rates used in the model are unit heat rates (total energy input divided by output net of station use.) An output of the production cost model is the total fuel cost, which the model calculates by multiplying the total fuel btu's by the fuel cost in $1 btu.

Prepared by: Lena M. Mantle

95. On page 7 (lines 7-9) of the testimony of John P. Cassidy, Mr. Cassidy makes the following statements: "Once annualized fuel and purchased power was calculated using the Staff's production cost model, I checked some of the fuel outputs for reasonableness. Staff witness Bender's production cost model appears to be reasonable."

a. Describe in as much detail as you can the methods used by Mr. Cassidy to determine the reasonableness of the results generated by this production cost model.

Staff Response: I performed the following historical analysis checks for reasonableness for the fuel area: Fuel price inputs, Maximum capacities, Planned outage hours, Force outage hours, Equivalent availability, Capacity factors, Total fuel cost per net KWH, Energy generated. Subsequent to the Staffs direct testimony filing, it was discovered that the economic loading order of the filed fuel run was not correct. Staffs filed fuel run loads the more expensive Meramec plant before the less expensive Sioux plant. Since Meramec is a "higher cost" plant, this error awards the Company with more fuel expense than should be allowed in the cost of service calculation. The Staff plans to correct this error in the context of its update to the fuel run as was discussed in the Direct testimony of Leon Bender.

Prepared by: John Cassidy

b. Identify each document reviewed or created by Mr. Cassidy in this process of evaluating reasonableness.

Staff Response: I primarily reviewed the following documents: FERC Form 1 (1996-2000) Electric plant data, Leon Bender's Production Cost Model, Fuel prices for twelve months ending December 31, 2000, AmerenUE Monthly Financial Reports, Five year averages of forced and scheduled outages (per DR 4114 and 4146). I checked various inputs/outputs from the fuel run. No documentation was retained during this review.

Prepared by: John Cassidy

c. Identify all other Staff employees who evaluated the reasonableness of the results generated by this production cost model.

<u>Staff Response</u>: **John Cassidy, Greg Meyer, Mike Proctor and Leon Bender.**

<u>Prepared by</u>: **John Cassidy**

d. For each person named in response to sub-part (c), describe in as much detail as you can the methods used by that person to determine the reasonableness of the results generated by the production cost model.

<u>Staff Response</u>: **Discussions were held between Greg Meyer and myself about the items described in 95 a. and 95 b. above. Greg also participated in checking the reasonableness of the fuel run. Leon Bender discussed the production cost model outputs in various informal discussions. Mike Proctor was involved with Leon in completion of the production cost model.**

<u>Prepared by</u>: **John Cassidy**

e. For each of the individuals named in response to sub-part (c), identify the documents reviewed or created by that person in the process of evaluating reasonableness.

<u>Staff Response</u>: **See item 95 d. above.**

<u>Prepared by</u>: **John Cassidy**

f. Identify each document that forms the basis of, or that otherwise supports, the conclusion of Mr. Cassidy that Mr. Bender's production cost model "appears to be reasonable."

<u>Staff Response</u>: **I performed informal reasonable checks on the production cost model outputs, however no documentation was retained. See item 95 b. above.**

<u>Prepared by</u>: **John Cassidy**

96. Do you contend that salvage expenses should be treated as a distribution expense (averaged over 10 years) rather than as part of the depreciation expense?

Staff Response: **No.**

Prepared by: **James D. Schwieterman**

Staff Response: **No.**

Prepared by: **Jolie Mathis**

a. Explain in as much detail as you can the basis for this contention.

Staff Response: **It is my contention that since the depreciation rates proposed by Jolie Mathis of the Commission's Engineering & Management Service Department do not include net salvage costs as part of their calculation, that those costs are appropriate costs of retiring plant in service and should therefore be included in rates. My adjustment includes a ten-year average of those costs in operating expense. Since the cost of removal and salvage data used for this adjustment was not broken out by type of plant in the FERC Form 1, I chose to include all the costs in distribution expense.**

Prepared by: **James D. Schwieterman**

Staff Response: **See further response of James D. Schwieterman.**

Prepared by: **Jolie Mathis**

b. Identify each document that you rely on, that forms the basis of, or that otherwise supports this contention.

Staff Response: **The only documents that I relied on or support this adjustment have been supplied previously as workpapers.**

Prepared by: **James D. Schwieterman**

<u>Staff Response</u>: Paul Adam, Direct Testimony, Laclede Gas Company, Case No. GR-99-315, Depreciation, June, 1999; Paul Adam, Direct Testimony, St. Louis County Water Company, Case No. WR-2000-844, Depreciation, November, 2000; and Paul Adam, Direct Testimony, Empire District Electric Company, Case No. ER-2001-299, Depreciation, April. 2001.

<u>Prepared by</u>: Jolie Mathis

97. On page 10 (lines 8-16) of the testimony of Leon C. Bender, Mr. Bender refers to "spot sales."

a. Explain in as much detail as you can the meaning you give to "spot sales."

<u>Staff Response</u>: In the Staffs analysis of Ameren's purchases and sales of electricity, a separation was made between

1) **Contract purchases and sales that were either identified by Ameren as "capacity transactions" or appeared to be fixed in quantity and/or price over several hours.**

2) **Spot purchases and sales that appeared to vary in both magnitude and price on an hour-to-hour basis.**

In this context, the word "spot" is being used to broadly identify a purchase or sale of electricity whose price and quantity can vary from hour-to-hour based on wholesale market supply and demand conditions.

<u>Prepared by</u>: Mike Proctor

b. Identify each document that you rely on, that forms the basis of, or that otherwise supports the meaning you give to "spot sales."

<u>Staff Response</u>: Textbook definitions of "spot" market, purchases, sales, demand, supply and price are usually very precise For example, in Spot Pricing of Electricity by Fred C. Schweppe, Michael C. Caramanis, Richard D. Tabors

and Roger E. Bohn [Kluwer Academic Publishers; 1988; p. 7], the authors state: "The hourly spot price is defined in terms of marginal costs subject to revenue reconciliation." In this book the focus is on differences in supply and demand at various locations throughout the transmission network. Thus, the word "spot" appears to incorporate both temporal and spatial attributes.

The temporal meaning of spot is in "real time" or currently as opposed to a futures market or price that occurs before real time. In Introduction to Futures and Options Markets by John Hull [Prentice Hall; 1995], the author states: "A *futures contract is an agreement to buy or sell an asset at a certain time in the* future for a certain price." Also, the pamphlet U.S. Electricity Futures: Eastern Region, published by the New York Mercantile Exchange, states: "A commodity futures contract is a legally binding agreement to make or take delivery of a specific grade and volume of a physical commodity at an agreed price at a set date in the future."

The spatial meaning of "spot price" is the price at a specific node within the transmission system. More recently, these spot prices have been described as locational marginal prices (LMPs). LMPs are not the marginal costs at the various nodes, rather they represent what an increment of demand at the node would have to pay if that increment of load were supplied from the lowest bid generation not already serving load and capable of meeting the security constraints on the transmission system.

While textbooks have very precise meanings for the words "spot" and "futures contract," a broader application of these words was applied by the Staff to mean:

1) **Contract (futures/forward) purchase or sale: the purchase or sale of electricity contracted for at fixed prices and/or quantities ahead of the time at which the physical exchange of electricity is to take place; and**

2) **Spot (current) purchase or sale: the purchase or sale of electricity at a price and in a quantity consistent with the hourly variations in supply, demand and prices that occur in real time.**

Prepared by: **Mike Proctor**

98. Explain in as much detail as you can how the revenue from spot sales was accounted for in the cost of service run that forms part of the basis for your complaint in this case.

Staff Response: **No adjustment was made to the recorded revenues booked during the test year ending June 30, 2000.**

Prepared by: **Doyle Gibbs**

Staff Response: **The Staff did not adjust test year per book levels for spot sales.**

Prepared by: **John Cassidy**

99. Explain in as much detail as you can how the cost of spot sales was accounted for in the cost of service production expenses.

Staff Response: **The Staff did not adjust test year per book levels for spot sales.**

Prepared by: **John Cassidy**

100. Identify each document that you rely on, that forms the basis of, or that otherwise supports your accounting for the cost of spot sales explained in answer to the preceding Interrogatory.

Staff Response: **The Staff used the Company's "Electric Production Expense" expense workpapers as prepared in the context of the EARPS for the twelve month periods ending June 30, 1996 through June 30, 2000 to verify historical levels. It is the Staffs understanding that the level of Sales-Interchange of $(183,898,082) for the test period represents all sales outside of serving native load. The Staff did not make an adjustment to this test year level of sales that are beyond serving native load.**

Prepared by: **John Cassidy**

101. What do you understand is the meaning of the term "off-system sales"?

Staff Response: **The term "off-system sale" refers to an amount of power, which was not used by AmerenUE (Company) to serve native load customers but was instead sold to other entities. The power sold could have been generated by the Company, or purchased from other entities.**

Prepared by: **Alan J. Bax**

102. What do you understand is the meaning of the term "interchange sales"?

Staff Response: **The term "Interchange", refers to the "Electric power or energy that flows from one entity to another" as defined in the Glossary of Terms by the North American Electric Reliability Council (NERC). The electric power or energy could be a sale, a purchase, or other transaction. Thus, the term "interchange sale" refers to an amount of power or energy sold by the Company that flowed from its system to that of another entity.**

Prepared by: **Alan J. Bax**

103. Explain in as much detail as you can how the generation unit specific data, identified in Schedule 1 to the testimony of Leon C. Bender, was utilized in the Real Time production cost model.

Staff Response: **Unit specific data refers to values that are unique to each generating unit, such as: on-line date, retirement date, ramp rate, number of hours down before that unit is expected to do a cold startup, minimum uptime, minimum downtime, start spread, minimum capacity, maximum capacity, variable and fixed cost, startup cost, heat rate curves, startup fuel used, primary fuel used, supplemental fuel used, unit type, and sulfur dioxide emissions data. Unit specific data is input into the production cost model and is used by Real Time to model each unit in its production cost run to determine unit availability and the cost to startup and run that unit.**

Prepared by: **Leon Bender**

104. Identify each document that you rely on, that forms the basis of, or that otherwise supports your method of utilizing the data referenced in the preceding Interrogatory.

Staff Response: **The manual for Real Time explains in detail how each of the values of the unit specific data is used in the model. The manual is being provided by the vendor, along with a working copy of the model.**

Prepared by: **Leon Bender**

105. Explain in as much detail as you can how the unit maintenance history data, identified in Schedule 1 to the testimony of Leon C. Bender, was utilized in the Real Time production cost model.

Staff Response: **Unit maintenance history was used to determine an outage schedule and a five-year average of forced outage hours for each unit. The planned outage hours were averaged over five years and that number was used to set the planned outage hours for the model. The forced outage rate in the model was set such that the model produced approximately the same number of forced outage hours as the five-year average of forced outage hours on each major UE unit. The Real Time production cost model uses this to determine unit availability.**

Prepared by: **Leon Bender**

106. Identify each document that you rely on, that forms the basis of, or that otherwise supports your method of utilizing the data referenced in the preceding Interrogatory.

Staff Response: **The Staff normalizes outage schedules by using averages of outage hours. This method eliminates any non-recurring events which may skew the outage schedule during a particular year test year towards a more expensive unit or a less expensive unit. There are no documents that support this method.**

Prepared by: **Leon Bender**

Respectfully submitted,

DANA K. JOYCE
General Counsel

September 19, 2001

Steven Dottheim
Chief Deputy General Counsel
Missouri Bar No. 29149

Attorney for the Staff of the
Missouri Public Service Commission
P. O. Box 360
Jefferson City, MO 65102
(573) 751-7489 (Telephone)
(573) 751-9285 (Fax)
sdotthei@mail.state.mo.us

Certificate of Service

I hereby certify that copies of the foregoing have been mailed or hand-delivered to all counsel of record as shown on the attached service list this 19th day of September 2001.

S… vice List for
Case No. EC-2002-1
Verified: September 14, 2001 (rr)

James J. Cook
Ameren Services
P.O. Box 66149 (M/C 1310)
St. Louis, MO 63166

Office of the Public Counsel
P. O. Box 7800
Jefferson City, MO 65102

Robin E. Fulton
Schnapp, Fulton, Fall, McNamara & Silvey
135 E. Main St., P.O. Box 151
Fredericktown, MO 63645-0151

Robert C. Johnson
Lisa C. Langeneckert
Law Office of Robert C. Johnson
720 Olive Street, Suite 2400
St. Louis, MO 63101

Diana M. Vulysteke
…an Cave LLP
One Metropolitan Square
211 North Broadway, Suite 3600
St. Louis, MO 63102

Michael C. Pendergast
Laclede Gas Company
720 Olive Street, Room 1520
St. Louis, MO 63101

Robert J. Cynkar
Victor J. Wolski
Cooper, Carvin & Rosenthal
1500 K Street, N.W., Suite 200
Washington, DC 20005

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

The Staff of the Missouri Public Service Commission, Complainant,	)	
v.	)	Case No. EC-2002-1
Union Electric Company, d/b/a AmerenUE, Respondent.	)	

STAFF'S RESPONSES TO UNION ELECTRIC COMPANY'S FIRST REQUESTS FOR ADMISSION

The responses follow of the Staff of the Missouri Public Service Commission (Staff) to Union Electric Company (UE) requests that the Staff admit or deny each of the requests for admission in UE's First Requests For Admission, in accordance with 4 CSR 240-2.090 and MO. R. CIV. P. 59.01. The Staff's responses follow:

MATTERS REQUESTED TO BE ADMITTED AND RESPONSES

Although the Staff believes that various Union Electric Company (UE), d/b/a AmerenUE Admission Requests are objectionable, most request opinions and many are vague or indefinite, the Staff has attempted to respond to all of UE's Admission Requests as best it can. For example, UE's second experimental alternative regulation plan (EARP) ended on June 30, 2001. The fact of there having been a first EARP, a second EARP and February 1, 2001 filings by the Staff, Public Counsel and UE (as provided for in Section 7.g of the July 12, 1996 Stipulation And Agreement in Case No. EM-96-149) does not make UE's Admission Requests regarding performance-based regulation / incentive regulation relevant. Case No. EC-2002-1 is a complaint case regarding excessive rates charged by UE to its Missouri customers. The matter

Rackers 2
EXHIBIT
11-20-01 KF

of the first and second EARPs being causes of, or factors in, UE's rates being excessive is not relevant to the principal issues before the Commission in Case No. EC-2002-1: (1) whether UE's rates are excessive and (2) the determination of how excessive UE's rates are, if they are excessive.

UE requested that the Staff admit or deny that each of the following statements is true. The Staff's responses follow:

1. "State regulation takes the place of and stands for competition . . . ."

Staff Response: Staff generally denies this statement. State regulation is a product of a state's statutes, agency rules and regulations and case law. State regulation does not only apply to organizations that operate in a non-competitive environment. State regulation occurs in industries that are competitive. For example, Missouri has regulations related to the insurance industry that is a competitive industry.

Staff admits that it is generally said that utility regulation is intended to act as a surrogate for competition. Utility rate regulation is based on specific state and federal statutes. These statutes with related court and regulatory agency decisions define the underlying premise for regulation in a specific jurisdiction. For example, *State on inf. Barker v. Kansas City Gas Co.*, 254 Mo. 515, 163 S.W. 854, 857-58 (Mo. 1913) states, in part, as follows:

> That act is an elaborate law bottomed on the police power. It evidences a public policy hammered out on the anvil of public discussion. It apparently recognizes certain generally accepted economic principles and conditions, to wit: That a public utility (like gas, water, car service, etc.) is in its nature a monopoly; that competition is inadequate to protect the public, and if it exists, is likely to become an economic waste; that state regulation takes the place of and stands for competition...

Other state case law that makes reference to utility regulation as intended to act as a surrogate for competition is *May Dept. Stores Co. v. Union Electric Light & Power Co.*, 341 Mo. 299, 107

S.W.2d 41, 48 (1937) and *State ex rel.Utility Consumers Council of Missouri, Inc. v. Public Serv. Comm'n,* 585 S.W.2d 41, 47 (Mo.banc 1979).

2. Regulation is intended to simulate the efficiency constraints of competition.

Staff Response: Staff generally denies this statement. Regulation is a product of state and federal statutes, agency rules and regulations and case law. Regulation exists in competitive industries as well as non-competitive industries. Regulation in competitive industries would have no need to simulate the efficiency of competition because competition already exists. Regulation generally is intended to protect the public or promote the public welfare when the government cannot rely upon the related industries to act in the appropriate manner. The regulatory requirement that expenditures must be prudent/reasonable in order to be recovered seeks to hold utilities to the efficiency standard of cost minimization.

3. "Captive ratepayers of public utilities" (within the meaning of this phrase as used by Ronald L. Bible in his testimony on page 6 (line 27)) should bear the utility's expected costs of providing its service that are not the results of poor or inept management.

Staff Response: Staff denies this statement. Captive ratepayers of public utilities should pay just and reasonable rates for safe and reliable service. Because utilities operate as monopolies, regulation is required to set prices at a just and reasonable level. It is the regulatory agency's duty to determine a fair return and the appropriate revenue requirement for the utility, while maintaining reasonable prices for the ratepayer. The statement alleges that just and reasonable rates must be established based on "the utility's expected costs of providing its service that are not the results of poor or inept management." The term "expected" can mean projected costs that are not 'known and measurable." Generally, just and reasonable rates are not based on projected costs that are not known and measurable or violate the matching principle respecting revenues, expenses and rate base. Staff would admit that just and reasonable rates should include a consideration of the utility's costs of providing service that are not the results of "poor or inept"/imprudent management.

Respecting poor or inept management, the Missouri Western District Court of Appeals has stated in *State ex rel. Missouri Pub. Serv. Co. v. Fraas*, 627 S.W.2d 882, 887 (Mo. App. 1982) as follows:

> The record in this case indicates that inefficient management would tend to explain at least in part the short fall between the allowed and earned rates of return.[3]
>
> [3] Mismanagement would deprive a public utility of any complaint about insufficient earnings. A rate tariff is intended only to permit an opportunity to make the percentage rate of return determined by the Commission to be reasonable. As put by one authority, "the utility's return allowance might be compared with a fishing or hunting license with a limit on the catch. Such a license does not guarantee that the holder will catch anything at all; it simply makes the catch legal (up to a specified limit) provided the holder is successful in his own efforts." 1 Priest, Principles of Public Utility Regulation 202 (1969) (quoting Welch, Cases and Text on Public Utility Regulation 478 (Rev.Ed.1968)).

4. If a regulated utility provides its service for a lower-than-expected cost as a result of an efficient and competent management, the regulated utility should be allowed to earn more than its cost of service.

Staff Response: Staff denies this statement. Staff does not understand what the statement means that the "regulated utility should be allowed to earn more than its cost of service." A regulated utility can earn more than its cost of service whenever the company can generate more revenues than the cost to produce those services. A regulated utility should be allowed the opportunity to earn a reasonable rate of return on its prudent and reasonable investment. The Missouri Public Service Commission examined the issue of adjusting a Company's rate of return due to management decisions during a period from June 21, 1982 through June 20, 1989. The

Commission ultimately decided that it was not appropriate to adjust the rate of return the company is authorized to earn for its management decisions:

> . . . The Commission has determined that it is not appropriate to adjust the rate of return SWB will be authorized to earn for management decisions. Now the Commission determined that where it has made adjustments to ROE in other cases, these type of adjustments can rarely be supported by sufficient evidence to warrant such a decision. The difficulty of deciding how much value a certain management decision has in terms of ROE makes the determination almost impossible. The evidence in this case provided no real guide to the Commission on how to value the various allegations of inefficient management. The more appropriate method for making adjustments to a public utility's revenue requirement is where specific dollar adjustments can be addressed, not by adjusting the ROE.

Re Southwestern Bell Telephone Co., Case Nos. TC-89-14 et al., Report And Order, 29 Mo.P.S.C.(N.S.) 607, 654 (1989). See also *Re Missouri Public Service Co.*, Case Nos. ER-82-39 and WR-82-50, Report And Order (1982); *Re Empire District Electric Co.*, Case Nos. ER-83-42, Report And Order (1983); *Re Kansas City Power & Light Co.*, Case No. ER-82-66, Report And Order (1982); *Re Union Electric Co.*, Case No. ER-82-52, Report And Order (1982); *Re Union Electric Co.*, Case No. ER-83-163, Report And Order (1983); *Re Missouri Public Service Co.*, Case No. ER-83-40, Report And Order (1983); *Re Kansas City Power & Light Co.*, Case Nos. ER-83-49 et al., Report And Order (1983); *Re Southwestern Bell Telephone Co.,* Case No. TR-83-253, Report And Order (1983); *Re Kansas City Power & Light Co.*, Case Nos. EO-85-185 and EO-85-224, Report And Order (1986); *Re Southwestern Bell Telephone Co.,* Case Nos. TC-89-14 et al., Report And Order (1989).

5. In a competitive industry, if one and only one company achieves better-than-expected earnings due to a good management, that company should be able to keep those earnings.

Staff Response: Staff denies this statement. Staff does not understand the meaning of the phrase "should be able to keep those earnings." If the phrase "should be able to keep those earnings" means that a company can keep or retain those earnings in subsequent periods, then the statement would be false. A company that achieves earnings in a given period "keeps" or retains those earnings regardless of whether the company is in a competitive or non-competitive industry. A company in a competitive or non-competitive industry that achieves a certain level of earnings in a given period does not establish a guarantee or entitlement to that level of earnings for future periods.

6. Electric competition is expected to lead to a large amount of innovation in the sale of energy services and the electric commodity itself will be just a part of the products and services from which utilities will obtain earnings in a competitive market.

Staff Response: Staff neither admits or denies the above statement. Staff has not conducted any analysis related to the various groups' expectation(s) regarding innovation in the sale of energy services as a result of electric competition. If energy services are offered, the electricity commodity will likely be included with (i.e., bundled into) these energy services.

7. Regulation was put in place in the early 1900s at a time when the utility industry was competitive.

Staff Response: Staff neither admits nor denies. Staff has not performed any research on the history of regulation in the early 1900s or the competitive nature of the relative utility industry at the time regulation was introduced. The above statement does not identify (a) a specific utility industry (e.g., electric, natural gas, telephone, water, and sewer), which could have a substantially different history, perspective and timeframe than another utility industry, or (b) geographic location.

8. There is no indication that consumers pushed to be protected from competition in the utility industry.

Staff Response: Staff neither admits nor denies. Staff has not performed any research on the history of regulation, the competitive nature of the relative utility industry at the time regulation was introduced, or the consumer attitudes at the time regulation was introduced. The above statement does not identify (a) a specific utility industry (e.g., electric, natural gas, telephone, water, and sewer), which could have a substantially different history of consumer attitudes and perspectives than another utility industry, (b) a specific geographic location, or (c) a specific timeframe.

9. Significant gains can be achieved through market incentives unless you believe that rate of return regulation drives competitors to control costs and innovate just as well as markets do.

Staff Response: Staff denies this statement. Regardless of one's beliefs concerning the benefits of rate of return regulation, the lack of the robustness of the market, the existence of market power and poorly designed methods of implementation are factors that can prevent significant gains through market incentives.

10. Rewarding high cost utilities will direct resources towards those utilities that the market should be moving resources away from and likewise will deter the movement of customers and resources towards well managed low cost utilities that should be rewarded and encouraged to increase output.

Staff Response: Staff denies this statement. The Staff does not understand the meaning of the phrase "[r]ewarding high cost utilities." In the utility industry, the comparison of the costs of one utility to another utility does not conclusively prove that the lower cost company is well managed. (In the rate case where UE sought to place the Callaway nuclear generating unit in rates, the Commission stated that "industry averages do not create an industry standard of prudence." *Re Union Electric Co.*, Case Nos. EO-85-17 and ER-85-160, Report And Order, 27 Mo.P.S.C.(N.S.) 183, 193 (1985)). The cost difference can be a product of the characteristics of the respective utility service territories or customer usage patterns. Rural or less densely populated service territories can have a higher cost per customer than urban service territories. Customer usage patterns that are more devoted to on-peak times versus usage patterns that occur off-peak time will have a higher general cost structure. Also, the above statement assumes that customers can switch utilities on the basis of cost, which is not the case in Missouri.

11. After the passage of PURPA in 1978, it became more apparent that competition in the generation sector was feasible.

Staff Response: *Staff neither admits nor denies this statement.* Section 210 of PURPA states that not later than one year after the date of the enactment of PURPA the FERC shall prescribe such rules as it determines are necessary to encourage cogeneration and small power production. Section 210 further states that beginning on or before the date one year after any rule is prescribed by the FERC, each State regulatory authority shall implement such rule for each electric utility for which it has ratemaking authority. In 1980-81, the Commission adopted 4 CSR 240-20.060 to comply with Section 210 of PURPA respecting cogeneration and small power production. Since that time small power production and cogeneration have not developed in Missouri in any appreciable amount. The Staff has performed no analysis of whether after the passage of PURPA in 1978, it became more apparent that competition in the generation sector was feasible to the various stakeholder groups.

12. Some state regulatory commissions began competitive bidding procedures in the mid-1980s.

Staff Response: Staff neither admits nor denies this statement. The Staff has performed no analysis of the requirement by other state regulatory commissions for utilities to use competitive bidding procedures for acquiring generation resources

13. In June, 1998, the Task Force on Retail Competition of the Missouri Public Service Commission assumed that electric restructuring in Missouri would "be mandated."

Staff Response: Staff neither admits nor denies this statement. The Staff is able to find this statement implied in the document entitled *Final Report of the Task Force on Retail Electric Competition of the Missouri Public Service Commission*, produced and filed by the Task Force on Retail Competition. This document was dated and filed on May 1, 1998. A corrected version was filed on May 19, 1998 and states, in relevant part at page 2, as follows:

> The Commission made clear in its *Orders* that it established a Task Force "to study retail wheeling of electricity and related issues that will face this Commission in the event that retail electric competition should occur." Specifically the Commission asked the Task Force:
>
> - to compile a comprehensive plan for implementation of retail electric competition in the State of Missouri in the event legislation is enacted which authorizes it;
> - to survey activity in other jurisdictions implementing or studying retail wheeling; and
> - to identify specific issues which will face the Public Service Commission, and the state as a whole, should retail competition occur.
>
> The Commission created the investigatory docket as a formal means "to identify the risks and benefits that would face the state of Missouri in the event retail competition occurs." . . . .

The statement that it is assumed that electric restructuring will be mandated is made in a document entitled the *Electric Restructuring Plan for the Competitive Supply of Generation in Missouri by the Missouri Public Service Commission Staff* filed on June 12, 1998, in Case No.

EW-97-245. This phrase appears on page one and in context states that this was simply an assumption of the Staff made at that time, based upon information that was available to it, to direct its work effort. This phrase in context appears as follows on page 1:

> One of the primary reasons for the creation of Missouri Public Service Commission's (Commission's) Task Force on Retail Competition was to compile a comprehensive plan for implementation of retail electric competition in the State of Missouri in the event legislation is enacted which authorizes or mandates the competitive supply of generation to retail electric consumers. . . .
>
> The Staff of the Commission (Staff) having participated fully in the Working Groups and the Task Force will take this opportunity to present a comprehensive plan for restructuring in Missouri based upon the information currently available. *This plan adopts the same assumption of the Task Force that electric restructuring will be mandated*.. . .
>
> If circumstances change or information currently available to the Staff changes, *the Staff reserves the right to modify this plan.*

In this context the Staff was stating that it was not recommending that the state move to retail competition, but instead was presenting a plan if electric restructuring were to be mandated.

14. On June 12, 1998, the Staff proposed a "plan [to] provide some general policy direction and [to] make proposals for the implementation of retail competition."

Staff Response: Staff admits this statement. The Staff did make this statement on page 1 of its *Electric Restructuring Plan for the Competitive Supply of Generation in Missouri* filed June 12, 1998 in Case No. EW-97-245. This Plan was developed based upon information that was available to the Staff at that time and reflects the Staff's viewpoints, but not necessarily those of the Commission.

15. The introduction of competition provides utilities with powerful incentives to cut costs.

Staff Response: Staff denies this statement. The degree of competition will influence the degree to which the utility has incentives to cut costs. Competition can actually increase costs by offering customers new or higher quality products. Generally, marketing and advertising expenditures increase with the introduction of competition. It has been asserted to the Commission that the introduction of competition or the threat of competition does provide the incentive to reduce prices. (See the July 19, 1995 on-the-record presentation of the Stipulation And Agreement in Case No. ER-95-411, pages 65, 73 and 74 of the transcript.).

In the *Electric Restructuring Plan for the Competitive Supply of Generation in Missouri by the Missouri Public Service Commission Staff* filed on June 12, 1998, in Case No. EW-97-245, the Staff states at pages 3-4, in part, as follows:

> The third general policy consideration is the need to ensure that competition does not return Missouri to the days before rural electrification. High cost customers, remote locations and high risk customers must be kept on the system where reasonably possible. We achieved the lifestyle and economic stability we have today by ensuring all citizens could receive the basic necessities in a modern society. Electricity was a fundamental necessity to bring all consumers to a certain standard of life. Any legislation establishing competition for retail electric service should maintain this public policy goal.

16. "In fixing rates for utility service, commissions must look to the present and the future. The level of rates to be determined is for today and tomorrow -- not yesterday."

Staff Response: Staff denies this statement. Staff has not preformed a study of the criteria that other commissions must follow in order to establish rates for utility service. Missouri statutes do not require the Commission to "look to the present and the future" or that the "level of rates to be determined is for today and tomorrow -- not yesterday". Missouri statutes require that the Commission establish rates that are "just and reasonable". The Western District Court of Appeals stated in *State ex rel. Fraas v. Public Serv. Comm'n*, 627 S.W.2d 882, 886 (Mo.App. 1981) that "the Commission must make an intelligent forecast with respect to the future period for which it is setting the rate; rate making is by necessity a predictive science. State v. N.J. Bell

Tel. Co., 30 N.J. 16, 152 A.2d 35 (1959)." In setting a rate, the Commission can look to yesterday for predicting the future.

17. "Normalization" adjustments to test year figures are used to eliminate non-recurring items of expenses or revenues.

Staff Response: Staff admits this statement. The appropriate use of normalization adjustments includes elimination of non-recurring expense or revenue items or levels from test year results.

18. The earnings of Ameren's unregulated generation business may not be considered in setting the proper rate of return for UE's electric distribution business.

Staff Response: Staff denies this statement. This statement lacks the specificity required to make a definitive response. Regulated and unregulated activities may be, and often are, commingled when measurement of the separate activities is an issue. Staff is not aware of an acceptable method to establish a rate of return for the distribution portion of a vertically integrated utility. Investors generally are not privy to the segment earnings results of regulated distribution activities versus unregulated generation business. Investors receive financial information that commingles regulated and unregulated results. A Staff response to a particular situation would consider the extent that the earnings of the unregulated generation business may be, or are, affected by affiliate transactions that are determined by Staff to be inappropriate for ratemaking purposes.

19. The cost of equity is the minimum expected rate of return necessary to attract equity capital to an investment.

Staff Response: Staff denies this statement. Staff's recommended range for cost of equity capital is an "estimate" of a company's cost of equity capital or rate of return on equity, not a minimum rate of return on equity. Often, the cost of equity capital is established at levels higher than returns that are still capable of attracting capital investment in a utility. Staff determines a range of reasonableness that is adequate, under efficient and economical management, to maintain and support the utility's financial standing, as well as allow the utility the opportunity to earn the revenue requirement determined to be appropriate.

20. The cost of equity is an opportunity-cost concept based on the recognition that investors face a variety of investment opportunities, so that the expected rate of return on any equity investment must be sufficient to compensate investors for the expected rate of return on foregone equity investments of similar risk.

Staff Response: Staff denies this statement. Opportunity cost occurs when the company determines what to do with its earnings. The company can either pay those earnings out in dividends or retain those earnings to grow the company or some combination of the two. If the company believes the investors have the opportunity to earn a greater rate of return for a comparable level of risk in other investments outside of the company, it will pay the majority of its earnings out to the investors in the form of dividends to afford them the opportunity to make those investments. If the company believes it can earn a comparable or higher level of return for the investor at a comparable level of risk by using the funds internally, the company will retain its earnings and not pay them out in dividends.

21. The cost of equity is a market price expressed in terms of the expected return per dollar equity invested.

Staff Response: Staff denies this statement. Cost of equity estimation methods and models have their own way of examining investor behavior and expectations. Each has its own premises and its own set of simplifications of reality. Staff is uncertain what is meant by "per dollar equity invested." This statement does not differentiate between investments by an outside investor and the corporation.

22. The basic proposition underlying the cost-of-equity concept is that at any point in time stocks are priced so that all stocks of equivalent risk offer the same expected rate of return.

Staff Response: Staff denies this statement. Cost of equity estimation methods and models have their own way of examining investor behavior and expectations. Each has its own premises and its own set of simplifications of reality

23. CAPM is consistent with the notion of no arbitrage.

Staff Response: Staff denies this statement. CAPM is based on the notion that there exists a risk free investment that offers a risk free rate of return. For investors to assume more risk in an alternative investment than they would with the risk free investment, they would require a risk premium above the risk free rate. Staff is uncertain what is meant by "no arbitrage" as it is used in this statement.

24. Risk is measured by beta in CAPM.

Staff Response: Staff denies this statement. The term risk as used in CAPM includes systematic and unsystematic risk. Beta is a measure of systematic risk. It is not a measure of unsystematic risk. It is an index of the volatility of the individual asset relative to the volatility of the market.

25. The DCF model for measuring the cost of equity is based on the notion that investors determine the price of a stock by estimating the present value of all future dividends to be paid by the company

Staff Response: Staff denies this statement. The Discounted Cash Flow (DCF) methodology is based on the premise that investors value an asset on the basis of future cash flows (i.e., dividends and ultimate sale in the case of common stocks) they expect to receive from owning the asset. Within this context, the current price of the company stock is equal to the present value equivalent of the expected dividends and the expected proceeds from eventually selling the stock. The discount rate that makes the future anticipated dividends and future anticipated selling price equal to the current market price is the cost of common equity.

26. The justification for using the DCF method to determine the cost of equity rests on the theory that, by establishing the current market price of the stock, investors make known the required rate of return by which they had implicitly or explicitly discounted their expected cash flows.

Staff Response: Staff denies this statement. By establishing the market price investors make known the return they expect to receive based on expected cash flows. The DCF model is not a required return model, it is an expected return model. DCF is based on the notion that investors value an asset on the basis of future cash flows (i.e., dividends and ultimate sale in the case of common stocks) they expect to receive from owning the asset. Within this context, the current price of the company stock is equal to the present value equivalent of the expected dividends and the expected proceeds from eventually selling the stock. The discount rate that makes the future anticipated dividends and future anticipated selling price equal to the current market price is the cost of common equity.

27. In a ratemaking relying on the DCF method, cost of equity cannot be valued by the stream of expected income of the subject company "because setting that stream of income [is] the very object of the rate proceeding".

Staff Response: Staff denies this statement. The ratemaking process does not establish the stream of income that a utility will earn. Income is the product of several factors. The ratemaking process determines the rates a utility can charge for its various regulated services. These rates are a significant factor in the determination of the actual company revenues. However, these rates are not the only factor in the determination of actual utility revenues. Revenues are determined by the number of units sold by the company to its ratepayers times the price per unit. For example, assume a company is allowed to charge $1.00 per unit and sells 1000 units in one month. Its revenues would be $1,000. Assume in a subsequent month, a company sells 2000 units due to increased demand from its customers. Its revenues for that month would be $2,000. Rate per unit has not changed. However, units sold have changed, which will impact the revenues earned by the company. Factors such as weather for residential customers and economic factors for industrial customers determine the volume of services consumed.

28. *Competition provides better incentives for efficient operation of a company than* traditional cost of service regulation.

Staff Response: Staff denies this statement. The validity of this statement is dependent on the level of market power and competition. Also, see the Staff response to admission request number 15 above.

29. Incentive or performance-based ratemaking provides better incentives for efficient operation of a company than traditional cost of service regulation.

Staff Response: Staff denies this statement. The validity of this statement is dependent on the design of the incentive or performance-based ratemaking alternative. A poorly designed incentive or performance-based ratemaking alternative can result in less efficient operation than traditional cost of service regulation. Incentives based upon performance in certain areas being measured may cause companies to commit additional resources to those areas at the expense of other functions not being measured. This diversion of funds may cause adverse effects over a period of time and can delay the recognition of problems. Frequently, the cost to correct the situation is greater than if the diversion of funds had not occurred. An example of this situation, is the diversion of funds from tree trimming activities, leading to long-term effects upon costs and the reliability of the company's electric distribution system, once the inevitable ice storm or high winds occur.

In Case No. GT-2001-329, In the Matter of Laclede Gas Company's Tariff Filing To Implement An Experimental Fixed Price Plan And Other Modifications To Its Gas Supply Incentive Plan, the Staff has taken the position that the present Laclede incentive / performance-based ratemaking plan does not provide better incentives for efficient operation of Laclede than traditional cost of service regulation.

30. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

Staff Response: Staff admits this statement which can be found in *Los Angeles Gas & Elec. Corp. v. California R.R. Comm'n*, 289 U.S. 287, 319, 53 S.Ct. 637, 649 (1933). Changes in opportunities for other investments may change investors' expectations regarding the rate of return to be earned by investing in a particular company. Should investors deem the stock of a particular company a more desirable investment compared to other companies' stock, demand for such stock may, in turn, drive up the price of that stock. For example, assume the stock price of a company increases yet the dividend remains the same. All else remaining the same, the dividend yield would decrease, therefore, making the overall cost of capital lower for that particular company.

31. The ability of a utility to pay dividends is in large part determined by the earnings of the company.

Staff Response: Staff denies this statement. The ability of a utility to pay dividends is in large part determined by the earnings of a company. However, there are a number of other factors that affect the ability, and willingness, of a company to pay dividends, which include but are not limited to: (1) management decisions, (2) decisions regarding expenditures, (3) cost control, (4) payout policy and (5) retention policy. (See the Staff response to admission request number 27 above).

32. The ratemaking process determines what revenues from regulated activities a utility can expect to achieve.

Staff Response: Staff denies this statement. The ratemaking process determines the rates a utility can charge for its various regulated activities. These rates are a significant factor in the determination of a utility's actual revenues. However, these rates are not the only factor in the determination of a utility's actual revenues. Factors such as weather for residential customers and economic factors for industrial customers determine the volume of services consumed. The ratemaking process, in general, establishes a relationship between revenues, expenses and rate base and rate of return components of the revenue requirement. The ratemaking process establishes this relationship for these components at a consistent point in time (i.e., test year period, update period or true-up period).

The revenues from regulated activities that a utility can expect to achieve will be the product of the rates that it is authorized to charge applied to regulated activity usage. The ratemaking process considers the usage of regulated activities when rates are determined. Ultimately, the customer chooses the actual usage of regulated activities when the customer decides to use the products.

33. On page 27 of "Missouri Public Service Commission Staff's Report Regarding the Experimental Alternative Regulation Plans of Union Electric Company, d/b/a AmerenUE, filed on February 1, 2001 in Case No. EM-96-149, your calculations of "excess revenues" are based on the Staff-determined required "equity returns" as follows:

Sharing Period	Excess Revenues	Equity Returns
7/1/95-6/30/96	$172,000,000	9.38%
7/1/96-6/30/97	$167,000,000	8.88%
7/1/97-6/30/98	$174,000,000	9.24%
7/1/98-6/30/99	$133,000,000	10.25%

Staff Response: Staff admits this statement. The 8.88% equity return used to calculate the $167,000,000 of excess earnings was not determined in the same manner as the other equity returns listed. Determining the equity return in the same manner as the others listed results in 9.54%, which equates to excess earnings of $146,000,000. Not long after the EARP report was filed the Staff realized the situation described above, notified UE and provided the revised calculations to the Company for the 7/1/96 – 6/30/97 sharing period.

September 5, 2001

Respectfully submitted,

DANA K. JOYCE
General Counsel

Steven Dottheim
Chief Deputy General Counsel
Missouri Bar No. 29149

Attorney for the Staff of the
Missouri Public Service Commission

P. O. Box 360
Jefferson City, MO 65102
(573) 751-7489 (Telephone)
(573) 751-9285 (Fax)
sdotthei@mail.state.mo.us

Certificate of Service

I hereby certify that copies of the foregoing have been mailed or hand-delivered to all counsel of record as shown on the attached service list this 5th day of September 2001.

vice List for
ase No. EC-2002-1
Verified: July 19, 2001 (rr)

James J. Cook
Ameren Services
P.O. Box 66149 (M/C 1310)
St. Louis, MO 63166

Office of the Public Counsel
P. O. Box 7800
Jefferson City, MO 65102

Robin E. Fulton
Schnapp, Fulton, Fall, McNamara & Silvey
135 E. Main St., P.O. Box 151
Fredericktown, MO 63645-0151

Robert C. Johnson
Lisa C. Langeneckert
Law Office of Robert C. Johnson
720 Olive Street, Suite 2400
St. Louis, MO 63101

Diana M. Vulysteke
Bryan Cave LLP
e Metropolitan Square
1 North Broadway, Suite 3600
St. Louis, MO 63102

Exhibit No.:	
Issues:	Income Tax Expense Deferred Income Taxes Pension Liability
Witness:	Stephen M. Rackers
Sponsoring Party:	MoPSC Staff
Type of Exhibit:	Direct Testimony
Case No.:	EC-2002-1
Date Testimony Prepared:	July 2, 2001

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

DIRECT TESTIMONY

OF

STEPHEN M. RACKERS

UNION ELECTRIC COMPANY d/b/a AMERENUE

CASE NO. EC-2002-1

Rackers 3
EXHIBIT
11-20-01 KF

Jefferson City, Missouri
July 2001

****Denotes Proprietary Information****

P

TABLE OF CONTENTS

STEPHEN M. RACKERS

UNION ELECTRIC COMPANY

d/b/a AMERENUE

CASE NO. EC-2002-1

DIRECT TESTIMONY

OF

STEPHEN M. RACKERS

UNION ELECTRIC COMPANY

d/b/a AMERENUE

CASE NO. EC-2002-1

Q. Please state your name and business address.

A. Stephen M. Rackers, 815 Charter Commons Drive, Suite 100 B, Chesterfield, Missouri 63017.

Q. By whom are you employed and in what capacity?

A. I am a Regulatory Auditor V in the Accounting Department, in the St. Louis Office, for the Missouri Public Service Commission (Commission).

Q. Please describe your educational background.

A. I graduated from the University of Missouri at Columbia, Missouri in 1978, from which I received a Bachelor of Science degree in Business Administration, majoring in Accounting. I have passed the Uniform Certified Public Accountant examination and am currently licensed in the state of Missouri.

Q. What has been the nature of your duties while in the employ of this Commission?

A. I have supervised and assisted in audits and examinations of the books and records of public utility companies operating within the State of Missouri. I have listed cases in which I have previously filed testimony on Schedule 1.

Q. With reference to Case No. EC-2002-1, have you made an investigation of the books and records of Union Electric Company d/b/a AmerenUE (UE or Company)?

A. Yes, with the assistance of other members of the Commission Staff (Staff).

Q. What is the purpose of your direct testimony?

A. My direct testimony will discuss the following items:

1) The Staff's calculation of income taxes;
2) The balance of deferred income taxes, which reduces Rate Base and appears on Accounting Schedule 2; and
3) The balance of the pension liability, which also reduces Rate Base.

Q. Please list the Accounting adjustments, schedule balances and schedules you are sponsoring.

A. I am sponsoring the following Accounting schedule balances, adjustments and schedules

Accounting Schedule 2 **Rate Base**

Deferred Income Tax Balance

Pension Liability Balance

Accounting Schedule 10 **Adjustments to Income Statement**

S-28.1 Annualization of Current Income Taxes

S-29.1 Annualization of Deferred Income Tax

Accounting Schedule 11 **Income Tax**

INCOME TAX EXPENSE

Q. Please provide a brief discussion of the methodology the Staff has used in its calculation of income taxes.

A. With two exceptions, the Staff is following the methodology used and agreed to by the parties in the calculation of income tax expense in both of the Company's Experimental Alternative Regulatory Plans (EARPs). The first exception is the exclusion of unbilled gross receipts taxes and the second is an adjustment to the amount of tax straight-line depreciation.

Q. Please explain the unbilled gross receipts tax item.

A. **Unbilled gross receipts taxes are a component of revenues and expenses included in the Company's per-book income statement, which is the starting point for the ratemaking calculation. In its calculation of income taxes, however, UE begins with a net income amount, which excludes unbilled revenue. As a result its income tax calculation also includes an adjustment to eliminate the gross receipts tax expense associated with unbilled revenue.**

Q. **Has the Company stated its opinion regarding the appropriateness of including this item in the ratemaking calculation of income taxes?**

A. **Yes. The Staff questioned this item in the most recent EARP credit calculation and the Company provided a written response, as a follow-up to a meeting with UE personnel, stating: "This item should not be included in the ratemaking calculations."**

Q. How is the Staff proposing to treat this item?

P

A. The Staff believes this item should be eliminated from the calculation of income taxes. As I stated before, this adjustment would be necessary, absent any other income statement adjustment. However, the Staff's income statement has already been adjusted to remove gross receipts taxes. As a result the Staff's calculation of income taxes, which will begin with its net income amount, needs no further adjustment for gross receipts taxes to arrive at the appropriate level of taxable income.

Q. Please explain the adjustment to tax straight-line depreciation.

A. The Staff is proposing to calculate tax straight-line depreciation consistent with the calculation of book depreciation expense.

Q. Please explain the relationship between tax straight-line depreciation and book depreciation.

A. Book depreciation is calculated by multiplying the depreciation rates, approved by the Commission, by the plant in service balances. A portion of this amount is expensed and reflected in the income statement as an expense and a reduction to net income. A portion of the amount is also capitalized as part of the cost of construction and included in the plant in service balances shown as an increase in the rate base. The total amount of book depreciation calculated is accumulated in a depreciation reserve, which is a reduction to the rate base. As long as the plant remains in service, depreciation associated with the plant will continue to be calculated.

For the purpose of calculating income taxes, however, the book depreciation is generally reduced to reflect tax straight-line depreciation. This is required to reflect the fact that the plant balances for book depreciation (book bases) are larger than the plant balances for tax depreciation (tax bases). The difference in book and tax bases generally results from the fact that certain items, for example capitalized payroll taxes, are capitalized for book purposes, but were deducted in the year incurred for tax purposes.

An additional reason why tax straight-line depreciation is lower than book depreciation is that UE stops calculating tax straight-line depreciation when the accumulated reserve, for a vintage year, equals the tax basis. For example, assume that a vintage (specific year) had depreciable plant additions of $1,000,000 and the weighted average book depreciation rate was 10%. UE would recognize $100,000 in tax straight-line depreciation annually for 10 years. At the end of year 10, the accumulated tax straight-line reserve would be equal to the tax basis of the property. No additional straight-line tax depreciation would be recognized in year 11 even though the plant investment was still in use and the Company continued to accrue (recognize) book depreciation for financial reporting and ratemaking purposes.

Q. Why does book depreciation continue to accrue on plant even though the tax straight-line reserve indicates full recovery of depreciation?

A. No attempt is made to track the accumulated book depreciation reserve by year (vintage). Book depreciation continues to be accrued for financial accounting and ratemaking purposes until the associated accumulated book depreciation reserve is equal to an entire plant account (all vintage year additions) and the Commission orders a 0% depreciation rate for that account. This method of depreciation is often referred to as mass asset accounting.

Q. Why is book depreciation computed on an entire plant balance (all vintages) instead of on an individual vintage basis used in computing tax depreciation and straight-line tax depreciation?

A. The mass asset accounting method used for book depreciation simplifies the accounting process. When an asset is retired, no attempt is made to determine the actual accumulated depreciation reserve for that asset. For example, when $1,000,000 of plant is retired, both the associated plant and accumulated depreciation reserve accounts are reduced by $1,000,000. This method treats all retired plant as though it was fully depreciated. The theory supporting this treatment is that while some amount of plant will be retired before the end of its depreciable life, an equal amount of plant will be retired after its depreciable life. Therefore, in the aggregate, it is assumed that early retirements of plant will be offset by an equal amount of late retirements.

Q. How is the revenue requirement affected by the continued recovery of book depreciation associated with plant that remains in service after its depreciable life and upon which tax straight-line depreciation is no longer calculated?

THE REMAINDER OF THIS PAGE INTENTIONALLY LEFT BLANK

A. Straight-line tax depreciation is substituted for book depreciation in the calculation of income taxes for ratemaking purposes. Referring to my previous example, book depreciation continued to be calculated in year 11 at $100,000 while tax straight-line depreciation was $0 after year 10. Therefore, while book depreciation continues, no associated deduction is available for the calculation of income taxes. The additional revenue requirement borne by customers associated with this situation is calculated below:

		Year 11
1.	Revenues	$ 100,000
2.	Book Depreciation	100,000
3.	Income before Income Tax	0
Add back:		
4.	Book Depreciation	100,000
Subtract:		
5.	Straight Line Tax Depreciation	0
6.	Taxable Income (Line 3 + 4 – 5)	100,000
7.	Income Tax Rate	38.39%
8.	Income Tax	38,390
9.	Tax Conversion Factor	1.62
10.	Revenue Requirement	$ 62,192

In summary, every dollar of book depreciation included in cost of service with no corresponding tax straight-line deduction results in approximately an additional $.62 cash outlay from ratepayers. This additional revenue requirement occurs because a plant asset remains in service longer than the "estimated" life used to compute the book depreciation rate for the asset.

Q. What is the Staff recommendation for calculating tax straight-line depreciation to address this situation?

A. The Staff is recommending the elimination of the additional revenue requirement resulting from book depreciation expense in cost of service, without a corresponding tax deduction, by continuing to calculate tax straight-line depreciation for all plant which is still in service. This treatment is consistent with the calculation of book depreciation.

Q. Has this issue been specifically addressed by the Commission?

A. Yes. In the St. Joseph Light and Power Company rate case, Case No. ER-93-41, the Commission heard this issue and ruled in favor of the Staff's position. This issue was presented in testimony in the Laclede Gas Company (Laclede) rate case, Case No. GR-94-220. Although the Commission did not hear the issue in the Laclede case, the Staff's position was adopted by Laclede and specifically addressed in the Stipulation And Agreement.

Q. Where do the unbilled GRT and additional tax straight-line depreciation appear?

A. These components are included in "Other Addbacks," which appears on Accounting Schedule 11, Income Tax, line 3. These components are included in the calculation of current income taxes, which appears on line 27 of Accounting Schedule 11.

Q. Please explain Accounting Adjustments S-28.1 and S-29.1.

A. These adjustments appear on page 9 of Accounting Schedule 10, Adjustments to Income Statement. The adjustments are determined by subtracting the test year current and deferred income tax amounts appearing on Accounting Schedule 9, Income Statement, from the current and deferred income tax amounts calculated on Accounting Schedule 11.

DEFERRED INCOME TAXES

Q. What methodology has the Staff used in its determination of the rate base offset for deferred income taxes?

A. Consistent with the other rate base components in the Staff's case, the offset for deferred income taxes reflects the balance at December 31, 2000. Also, except for two components, the Staff is including the same balances that were recognized and agreed to by the parties in the calculation of income tax expense in both EARPs. The first of these components deals with the recognition of deferred income tax balances from Account 283, Miscellaneous Accumulated Deferred Income Taxes. The second of these components concerns the elimination of the deferred income tax balance associated with Financial Accounting Standard Number 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" (FAS 106).

Q. Please explain the Staff's treatment of these deferred income tax balances.

A. The Staff is proposing to treat the deferred income tax balances in a consistent manner with the treatment that has been afforded the deferred income tax expense. The deferred income tax balances represent the accumulation of these prior deferred expenses.

With regard to the Account 283 deferred income tax balances, the parties have included the associated deferred income tax expense in the determination of prior years' credits for the EARPs. Therefore, it is appropriate to recognize the associated accumulated deferred income tax balances as proper offsets to rate base. It is inconsistent to include the deferred income tax expense in the determination of revenue requirement without also recognizing the deferred tax balance in the determination of rate base.

Regarding the FAS 106 accumulated deferred income tax balances, however, the parties have not included the associated deferred income tax expense in the determination of prior years' credits for the EARPs. Therefore, it is inappropriate to recognize the associated deferred income tax balances as a component of the offset to rate base. It is inconsistent to exclude the deferred income tax expense in the determination of revenue requirement, without also eliminating the accumulated deferred tax balance in the determination of rate base.

PENSION LIABILITY

Q. Please explain the pension liability rate base offset.

A. The pension liability rate base offset calculated by the Staff represents the difference between the amount expensed for pensions and the amount paid into the pension fund by the Company. The Staff has included pension expense in the prior years' determination of credits for the EARPs. This level of pension expense has exceeded the amount actually paid into the pension fund by UE.

Q. Please explain the relationship between pension expense and funding.

A. Prior to the beginning of the initial EARPs on July 1, 1995, UE's rates had reflected pension expense on a pay-as-you-go basis, including an amount that reflected actual payments to the pension fund. When the first EARP was established, the method of determining pension expense for ratemaking was changed, in accordance with Commission and Staff policy, to a method based on Financial Accounting Standard Number 87, "Employer's Accounting For Pensions" (FAS 87).

Pension expense calculated according to FAS 87 is based on a different calculation than the method used to determine the required level of pension funding. The level of funding is based on a method determined by the Employee Retirement Income Security Act of 1974 (ERISA). Although both methods employ actuarial techniques, the level of pension expense calculated according to FAS 87 can be quite different from the amount required to be funded according to ERISA.

For example, using the FAS 87 method, pension expense may be a negative amount. However, the funding requirement for ERISA cannot be less than $0. The difference between pension expense, according to FAS 87, and the amount funded according to ERISA is accumulated in a pension liability account, if the FAS 87 amount is greater than the ERISA amount, or in a pension asset account, if the FAS 87 amount is less than the ERISA amount.

Q. Why is it appropriate to include the difference between the pension amounts calculated according to FAS 87 and ERISA in rate base?

A. Including this difference recognizes the accumulated funds, provided by either ratepayers or the Company, that are associated with pensions. If the pension expense included in rates is greater than the level of pension funding, ratepayers have provided cash to UE and the difference should be a reduction to rate base. This is similar to the standard practice of including the accumulated balance of deferred income taxes as a reduction to rate base, since ratepayers are providing funds to the Company in excess of the level of income taxes actually paid. On the other hand, if the pension expense included in rates is less than the level of pension funding, UE has provided the cash necessary to fund pensions in excess of the level included in rates and this difference should be an increase to rate base. This is similar to the standard practice of including prepayments as an increase to rate base, since companies provide the funds to pay for these investments before they are reflected in expense.

Q. Has the difference between pension expense and funding been reflected in rate base for other companies?

A. Yes. It has become the standard practice of the Staff to reflect this difference in rate base. I have personally participated in rate cases for Missouri-American Water Company, Laclede and St. Louis County Water Company, where the Staff proposed and the Company accepted the inclusion, in rate base, of the difference between the pension expense included in rates and the amount actually funded. For Laclede, the rate base was increased due to including this difference and for the water companies, the rate base was reduced by this difference.

Q. How did the Staff determine the amount of the pension liability?

A. As previously discussed, the change to accounting for pension expense in rates according to FAS 87 for UE occurred at July 1, 1995. Therefore, the accumulated amount of the difference between the pension expense calculated according to FAS 87 and the amount actually funded, since July 1, 1995, has been included in the determination of rate base.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

The Staff of the Missouri Public Service Commission,	)	
	)	Case No. EC-2002-1
Complainant,	)	
vs.	)	
	)	
Union Electric Company, d/b/a AmerenUE,	)	
	)	
Respondent.	)	

AFFIDAVIT OF STEPHEN M. RACKERS

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Stephen M. Rackers, is, of lawful age, and on his oath states: that he has participated in the preparation of the foregoing Direct Testimony in question and answer form, consisting of 12 pages to be presented in the above case; that the answers in the foregoing Direct Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

Stephen M. Rackers

Stephen M. Rackers

Subscribed and sworn to before me this 29th day of June, 2001.

Toni M. Charlton

Notary Public

TONI M. CHARLTON
NOTARY PUBLIC STATE OF MISSOURI
COUNTY OF COLE
My Commission Expires December 28, 2004

RATE CASE PROCEEDING PARTICIPATION

STEPHEN M. RACKERS

Company	Case Number
Bowling Green Gas Company	GR-78-218
Central Telephone Company	TR-78-258
Empire District Electric Company	ER-79-19
Fidelity Telephone Company	TR-80-269
St. Louis County Water Company	WR-80-314
Union Electric Company	ER-81-180
Laclede Gas Company	GR-81-245
Great River Gas Company	GR-81-353
Union Electric Company	ER-82-52
Laclede Gas Company	GR-82-200
St. Louis County Water Company	WR-82-249
Union Electric Company	ER-83-163
Union Electric Company	ER-84-168
Arkansas Power and Light Company	ER-85-20
Kansas City Power and Light Company	ER-85-128
Arkansas Power and Light Company	ER-85-265
Union Electric Company	EC-87-114
Union Electric Company	GR-87-62
Southwestern Bell Telephone Company	TC-89-14
St. Louis County Water Company	WR-89-246
Laclede Gas Company	GR-90-120
Missouri Cities Water Company	WR-91-172
St. Louis County Water Company	WR-91-361
Laclede Gas Company	GR-92-165
Missouri Pipeline Company	GR-92-314
St. Louis County Water Company	WR-92-204

Company	Case Number
St. Louis County Water Company	WR-94-166
St. Louis County Water Company	WR-95-145
Union Electric Company	ER-95-411
St. Louis County Water Company	WR-96-263
St. Louis County Water Company	WR-97-382
Laclede Gas Company	GR-99-315
Missouri-American Water Company	WR-2000-281 et al
St. Louis County Water Company	WR-2000-844

Exhibit No.:	
Issues:	*Test Year* *Allocations* *Accounting Schedules* *Net Salvage Expense* *Reserve Amortization* *Office Supplies* *Property Insurance* *Depreciation Expense*
Witness:	*James D. Schweiterman*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Direct Testimony*
Case Nos.:	*EC-2002-1*
Date Testimony Prepared:	*July 2, 2001*

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

DIRECT TESTIMONY

OF

JAMES D. SCHWEITERMAN

UNION ELECTRIC COMPANY
d/b/a AMERENUE

CASE NO. EC-2002-1

Jefferson City, Missouri
July 2001

Reckers 4
EXHIBIT
11-20-01 kf

DIRECT TESTIMONY

OF

JAMES D. SCHWIETERMAN

UNION ELECTRIC COMPANY *d/b/a* AmerenUE

CASE NO. EC-2002-1

Q. Please state your name and business address.

A. James D. Schwieterman, P. O. Box 360, Jefferson City, Missouri 65102.

Q. By whom are you employed and in what capacity?

A. I am a Regulatory Auditor with the Missouri Public Service Commission (Commission).

Q. Please describe your educational background.

A. I attended Lincoln University in Jefferson City, Missouri, from which I received a Bachelor of Science degree in Business Administration, with a major in Accounting, in May 1975.

Q. What has been the nature of your duties while in the employ of this Commission?

A. Since joining the Commission in 1975, I have directed and assisted with the audits and examinations of the books and records of utility companies operating within the state of Missouri.

Q. Have you previously testified before this Commission?

A. Yes, I have. Please refer to Schedule 1, which is attached to this direct testimony, for a list of cases in which I have filed testimony.

Q. With reference to Case No. EC-2002-1, have you made an investigation of the books and records of AmerenUE (UE or Company)?

A. Yes, with the assistance of other members of the Commission Staff (Staff).

Q. Please identify your areas of responsibility in Case No. EC-2002-1.

A. My principal areas of responsibility are test year, office supplies expense, property insurance, allocations, depreciation expense and net salvage expense.

TEST YEAR

Q. What test year has the Staff used in this case?

A. The Staff has used a test year ending June 30, 2000. The test year was updated for certain material items (plant, depreciation reserve, customer levels, fuel expense, other operating expenses and rate of return/capital structure) through December 31, 2000, based on actual information available during the audit. Updating specific material test year items enables the Staff to make its rate recommendation based on more recent auditable information.

Q. What is a test year?

A. A test year is a twelve-month period used as the basis for the audit of any rate filing or complaint case. This period serves as the starting point for analyses and review of the utility's operations to set the reasonableness and appropriateness of the rate filing or complaint case for the prospective period when the rates will be in effect. The test year forms the basis for any adjustments necessary to remove abnormalities that may have occurred during the period and to appropriately reflect any increase or decrease shown in the financial records of the utility. Adjustments are made to the test year level of revenues, expenses and investment to determine the proper level of earnings. After the recommended rate of return that the utility is permitted the opportunity to earn is determined, a comparison to the results of existing rates is made to see if any additional revenues are necessary. If the Commission concludes that the utility's earnings are deficient, it will authorize the Company to increase its rates. Conversely, if existing rates generate earnings in excess of what prospectively should be authorized levels, the Commission may conclude that the utility's earnings are excessive, and may order the Company to reduce its rates. In summary, the test year, as adjusted, is the vehicle used to evaluate and determine the proper relationship between revenue, expenses and investment. This relationship is essential to determine the appropriate level of prospective earnings for a utility.

Q. Has the Staff performed any analysis to determine how UE's test year data compares with actual calendar year 2000 results?

A. Yes. The Staff performed an analysis of the operating expense accounts detailed on the Company's monthly 19607 report, by comparing the balances for the test year against the balances for twelve months ended December 31, 2000. Wherever material differences existed between the periods, the Staff first determined whether that particular account or type of expense was already being reviewed or analyzed by Staff. If the account was already being reviewed by other Staff members, then further review in this analysis was unnecessary. If the account was not already being reviewed, the Staff then tried to determine whether the difference was due to a non-recurring charge or some other adjustment to the account, or was due to an overall increase or decrease in the costs charged to that account. If the difference was due to a non-recurring charge or some other adjustment to the account, then that charge or adjustment was reviewed to determine whether any further adjustment to the test year by the Staff was necessary. If the difference was due to an overall increase or decrease in the charges to the account, then an adjustment was considered to adjust the account to what was deemed to be a more normal level.

Q. Do you have any examples of accounts or costs where material differences existed between the test year and calendar year 2000, and for which the Staff was already reviewing those accounts or costs?

A. Yes. Fuel expense is an area where cost was considerably greater during calendar year 2000 than during the test year. However, the Staff was already intending to normalize and adjust test year fuel expense to an annual level based on a fuel model using the Staff's normalized and annualized sales. Therefore, no further review in this analysis was necessary.

A second example was the power plant maintenance accounts. There were significant differences in power plant maintenance expense between the test year and calendar year 2000 expense. However, the Staff was reviewing and adjusting power plant maintenance expense for all of the Company's steam generating plants, and no further adjustment was considered necessary.

Another example was the outside services account. There were significant increases in calendar year 2000 costs over test year expenses. The Staff was already reviewing outside services costs, and had submitted several data requests to the Company. At a later meeting with Company representatives, it was explained by the Company that the majority of the cost increases in outside services were due to billings from Ameren Energy for transmission services. The Company representatives also explained that the cost increases were being offset fully by increased transmission revenues. As a result, no further adjustment to test year outside services expense was considered necessary.

Q. Do you have any examples of an account where a material difference existed between the test year and calendar year 2000 balances, the Staff was not reviewing that account, and a non-recurring cost or adjustment was causing the difference?

A. Yes. Transmission expense was considerably greater during calendar year 2000 than it was during the test year. The Staff determined that the difference was entirely due to a one-time expense accrual by the Company in the fourth quarter of 2000 ($25 million, total company), for an expected payment to the Midwest Independent System Operator (Midwest ISO), for costs incurred by the Midwest ISO, plus estimated exit fees to be charged the Company. An ISO operates but does not own electric transmission systems and maintains system reliability. The Company made the decision to withdraw from the Midwest ISO so that it could join the Alliance Regional Transmission Organization (Alliance RTO), and the one-time accrual was the best estimate of the Company's remaining obligation to the Midwest ISO. It is Staff's belief that permanent rates should not be set based upon non-recurring, one-time charges, and therefore, no further adjustment was necessary for this item.

Q. Are there any examples of an account where material differences existed between the test year and calendar year 2000 balances, the Staff was not reviewing that account, and a non-recurring cost or adjustment was not causing the difference?

A. Yes. The office supplies and property insurance expense accounts were two accounts where calendar 2000 costs were materially greater that the test year. The Staff made Income Statement adjustments S-19.11 and S-19.12 to normalize those accounts. These adjustments will be explained later in this testimony.

ALLOCATIONS

Q. What are the allocation factors that are being used by Staff in this case?

A. The Staff is using the Company allocation factors at December 31, 2000, with one exception. The Staff is using a different allocation factor for fixed costs. The fixed allocation factor is used to allocate most of the power plants, transmission plant, and the expenses associated with those facilities. Please refer to the direct testimony of Staff witness Alan J. Bax of the Commission's Energy Department for information regarding the development of Staff's fixed allocation factor.

ACCOUNTING SCHEDULES

Q. Please identify the Accounting Schedules you are sponsoring.

A. I am sponsoring the following Accounting Schedules:

Accounting Schedule 1	Revenue Requirement
Accounting Schedule 2	Rate Base
Accounting Schedule 5	Depreciation Expense
Accounting Schedule 9	Income Statement
Accounting Schedule 10	Adjustments to Income Statement

Q. Please explain Accounting Schedule 1, Revenue Requirement.

A. Accounting Schedule 1 is the calculation of revenue requirement for the rate of return range sponsored by Staff witness Ronald L. Bible of the Commission's

Financial Analysis Department. The rates of return determined by Staff witness Bible are applied to the Company's rate base, which is presented on Accounting Schedule 2, Rate Base, to determine the net income requirement. The gross revenue requirement is then determined by adding the required income taxes, calculated on Accounting Schedule 11, Income Tax, to the net income requirement. The direct testimony of Staff Accounting witness Stephen M. Rackers explains the calculation of income taxes on Accounting Schedule 11.

Q. Please explain Accounting Schedule 2, Rate Base.

A. Accounting Schedule 2 takes the Company's adjusted jurisdictional plant in service balance from Accounting Schedule 3, Total Plant in Service, and deducts the Company's adjusted jurisdictional depreciation reserve from Accounting Schedule 6, Depreciation Reserve, to compute the net plant in service. Added to net plant in service are amounts for cash working capital (CWC), materials and supplies, prepayments and fuel inventory. Rate base deductions include the federal income tax offset, state income tax offset, interest expense offset, customer advances, customer deposits, deferred income taxes and pension liability.

Q. How was the rate base component for CWC determined?

A. The Staff's calculation of the CWC rate base component will be discussed in the direct testimony of Staff Accounting witness Leasha S. Teel.

Q. How were the rate base addition components for materials and supplies, prepayments and fuel inventory determined?

A. The components for materials and supplies, prepayments and fuel inventory will be discussed in the direct testimony of Staff Accounting witness Paul R. Harrison.

Q. Please explain how the federal income tax offset, state income tax offset and interest expense offset were calculated.

A. The Staff's calculation of these items will be discussed in the direct testimony of Staff Accounting witness Teel.

Q. How were the rate base deduction components for customer advances and customer deposits determined?

A. The rate base components for these items will be discussed in the direct testimony of Staff Accounting witness Harrison.

Q. Please describe how the rate base deduction components of deferred income taxes and pension liability were determined.

A. The amount of the deduction of deferred income taxes and pension liability will be discussed in the direct testimony of Staff Accounting witness Rackers.

Q. Please explain Accounting Schedule 5.

A. Accounting Schedule 5, Depreciation Expense, lists in Column B the total electric depreciation and amortization expense by category, based on the Staff's proposed depreciation rates. The categories that are listed are local and directly assigned plant, power pool plant, and system general plant. The local and directly assigned plant category includes depreciation expense for nuclear and distribution plant, Callaway decommissioning expense and the amortization of the allowed Missouri merger costs. The power pool plant category includes depreciation and amortization expense of steam, hydraulic, other production and transmission plant. The system general plant category includes depreciation and amortization for intangible and general plant. These categories are used to allocate depreciation and amortization expense. Please refer to the direct testimony of Staff witness Jolie Mathis of the Commission's Engineering & Management Services Department for further information regarding the development of the Staff's proposed depreciation rates. Column C lists the allocated Missouri jurisdictional electric depreciation and amortization expense and adjustments by category, based on the Staff's proposed depreciation rates. Column D contains the Missouri jurisdictional income statement adjustment numbers that also appear on Schedule 10, Adjustments to Income Statement. Columns E and F depict the Illinois and Sales for Resale electric depreciation and amortization expense by category.

Q. Please explain Accounting Schedule 9.

A. Accounting Schedule 9, Income Statement, lists in Column B Company's total electric operating revenues and expense for the twelve months ended June 30, 2000. Columns C and E list Staff's adjustments to total electric and jurisdictional electric operating revenues and expense, respectively. Column D contains the Missouri jurisdictional allocation factors. Column F contains the Staff's adjusted jurisdictional electric operating revenues and expense.

Q. Please explain Accounting Schedule 10.

A. Accounting Schedule 10, Adjustments to Income Statement, lists the Staff's individual total electric and Missouri jurisdictional adjustments to the unadjusted test year income statement to derive Staff's adjusted net income, and also are shown in Columns C and E of Accounting Schedule 9, respectively. A brief explanation for each adjustment and the name of the Staff witness sponsoring the adjustment is included on Accounting Schedule 10.

Q. Please identify the Accounting adjustments you are sponsoring.

A. I am sponsoring the following adjustments:

Income Statement	S-14.1, S-14.2, S-14.6, S-19.11, S-19.12, S-21.1, S-21.2, S-21.3, S-22.1, S-22.2, S-22.3, S-23.1, S-23.2 & S-23.3

Q. Please explain Income Statement adjustment S-14.1.

A. Adjustment S-14.1 eliminates from operating expense the Illinois portion of distribution expense. This adjustment is necessary in order to eliminate any non-Missouri jurisdictional costs from operating expense.

NET SALVAGE EXPENSE

Q. Please explain Income Statement adjustment S-14.2.

A. Adjustment S-14.2 includes a ten-year average of net salvage costs in operating expense.

Q. What are net salvage costs?

A. Net salvage costs are the net costs resulting from the retirement of plant in service. These costs include the cost of removing or dismantling retired plant, referred to as cost of removal, less the gross salvage value of the disposition of the plant.

Q. Why is this adjustment necessary?

A. This adjustment is necessary because the Staff's proposed depreciation rates, for purposes of this case, do not include net salvage costs as part of their calculation. Since net salvage costs are legitimate costs of retiring plant in service, it is reasonable that those costs be recovered from the ratepayer by including them in operating expense.

Q. Why is a ten-year average of net salvage costs reasonable?

A. A ten-year average reflects a level of net salvage costs that the Company is currently experiencing, rather than an accrual through depreciation rates. Based on the value of the Staff's depreciation adjustment, a ten-year average is a more reasonable level of net salvage costs. Please refer to the direct testimony of Staff witness Mathis for further information concerning the elimination of net salvage costs from the Staff's proposed depreciation rates.

RESERVE AMORTIZATION

Q. Please explain Income Statement adjustment S-14.6.

A. Adjustment S-14.6 amortizes the over-accrued accumulated depreciation reserve over a twenty-year period. Please refer to the direct testimony of Staff witness Mathis for further information concerning the over-accrued depreciation reserve, and the twenty-year amortization period.

OFFICE SUPPLIES

Q. Please explain Income Statement adjustment S-19.11.

A. Adjustment S-19.11 increases operating expense to reflect a normalized level of office supplies expense based on a five-year average.

Q. Why is this adjustment necessary?

A. Subsequent to the test year, the Staff analyzed all operating expense accounts by comparing the balances for the test year against the twelve months ended December 31, 2000, as was explained earlier in this testimony. The analysis revealed that calendar 2000 office supplies expense was materially greater than the test year amount. After further analysis of the account did not reveal a non-recurring charge or adjustment, it was determined that an adjustment to normalize the test year amount was appropriate. Staff chose to use a five-year average of office supplies expense because of the fluctuation of the amounts charged to the account over the past five years.

PROPERTY INSURANCE

Q. Please explain Income Statement adjustment S-19.12.

A. Adjustment S-19.12 increases operating expense to reflect a normalized level of property insurance expense based on a five-year average. This adjustment is based on the same methodology as the previous adjustment, No. S-19.11.

DEPRECIATION EXPENSE

Q. Please explain Income Statement adjustments S-21.1, S-21.2 and S-21.3.

A. Adjustment S-21.1 adjusts book depreciation expense on local and directly assigned electric plant in service for the test year ended June 30, 2000 to an annualized level at the Staff's proposed depreciation rates based on local and directly assigned electric plant in service at June 30, 2000. Annualized depreciation expense is calculated by multiplying the amount in each local and directly assigned electric plant in service account by the Staff's proposed annual depreciation rate for that account. The depreciation expense is then allocated as Missouri jurisdictional depreciation expense based on the allocation factors at December 31, 2000.

Adjustment S-21.2 updates annualized depreciation expense on local and directly assigned plant to an annualized level at the Staff's proposed depreciation rates based on local and directly assigned electric plant in service at September 30, 2000. The depreciation expense is then allocated as Missouri jurisdictional depreciation expense based on the allocation factors at December 31, 2000.

Adjustment S-21.3 updates annualized depreciation expense on local and directly assigned plant to an annualized level at the Staff's proposed depreciation rates based on local and directly assigned electric plant in service at December 31, 2000. The depreciation expense is then allocated as Missouri jurisdictional depreciation expense based on the allocation factors at December 31, 2000.

Q. Please explain Income Statement adjustments S-22.1, S-22.2 and S-22.3.

A. Adjustment S-22.1 adjusts book depreciation expense on power pool electric plant in service for the test year ended June 30, 2000 to an annualized level at the Staff's proposed depreciation rates based on power pool electric plant in service at June 30, 2000. Annualized depreciation expense is calculated by multiplying the amount in each power pool electric plant in service account by the Staff's proposed annual depreciation rate for that account. The resulting depreciation expense is then allocated as Missouri jurisdictional depreciation expense based on the allocation factors at December 31, 2000.

Adjustment S-22.2 updates annualized depreciation expense on power pool electric plant to an annualized level at the Staff's proposed depreciation rates based on power pool electric plant in service at September 30, 2000. The depreciation expense is then allocated as Missouri jurisdictional depreciation expense based on the allocation factors at December 31, 2000.

Adjustment S-22.3 updates annualized depreciation expense on power pool electric plant to an annualized level at the Staff's proposed depreciation rates based on power pool electric plant in service at December 31, 2000. The depreciation expense is then allocated as Missouri jurisdictional depreciation expense based on the allocation factors at December 31, 2000.

Q. Please explain Income Statement adjustments S-23.1, S-23.2 and S-23.3.

A. Adjustment S-23.1 adjusts book depreciation expense on system general electric plant in service for the test year ended June 30, 2000 to an annualized level at the Staff's proposed depreciation rates based on electric plant in service at June 30, 2000. Annualized depreciation expense is calculated by multiplying the amount in each system general electric plant in service account by the Staff's proposed annual depreciation rate for that account. The depreciation expense is then allocated as Missouri jurisdictional depreciation expense based on the allocation factors at December 31, 2000.

Adjustment S-23.2 updates annualized depreciation expense on system general plant to an annualized level at the Staff's proposed depreciation rates based on electric plant in service at September 30, 2000. The depreciation expense is then allocated as Missouri jurisdictional depreciation expense based on the allocation factors at December 31, 2000.

Adjustment S-23.3 updates annualized depreciation expense on system general plant to an annualized level at the Staff's proposed depreciation rates based on electric plant in service at December 31, 2000. The depreciation expense is then allocated as Missouri jurisdictional depreciation expense based on the allocation factors at December 31, 2000.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

The Staff of the Missouri Public Service Commission,	)	Case No. EC-2002-1
	)	
Complainant,	)	
vs.	)	
	)	
Union Electric Company, d/b/a AmerenUE,	)	
	)	
Respondent.		

AFFIDAVIT OF JAMES D. SCHWEITERMAN

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

James D. Schweiterman, is, of lawful age, and on his oath states: that he has participated in the preparation of the foregoing Direct Testimony in question and answer form, consisting of 14 pages to be presented in the above case; that the answers in the foregoing Direct Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

James D. Schweiterman

James D. Schweiterman

Subscribed and sworn to before me this 28th day of June, 2001.

Toni M Charlton

Notary Public

TONI M. CHARLTON
NOTARY PUBLIC STATE OF MISSOURI
COUNTY OF COLE
My Commission Expires December 28, 2004

RATE CASE PROCEEDINGS PARTICIPATION

JAMES D. SCHWIETERMAN

COMPANY	CASE NO.
Arkansas-Missouri Power Company	ER-77-116
Associated Natural Gas Company	GR-77-117
Capital City Water Company	WR-94-297
Central Telephone Company	TR-78-258 TR-81-59
Choctaw Telephone Company	TR-91-336
Continental Telephone Company of Missouri	TR-82-223
Cuivre River Electric Service Company	EA-86-13
Empire District Electric Company	ER-79-19 ER-83-42 ER-90-138 ER-94-174 ER-97-81
Gas Service Company	GR-78-70
Laclede Gas Company	GR-78-148 GR-83-233
Missouri-American Water Co.	WR-95-205 SR-95-206
Missouri Cities Water Company	WO-86-122
Missouri Utilities Company	GR-81-244 WR-81-248 ER-81-346
Ozark Natural Gas Company	GA-98-227
Missouri Water Company	WR-77-212
St. Joseph Light and Power Company	EC-98-573 HR-99-245 GR-99-246 ER-99-247

RATE CASE PROCEEDINGS PARTICIPATION

JAMES D. SCHWIETERMAN

COMPANY	CASE NO.
St. Louis County Water Company	WO-86-100
Sho-Me Power Corporation	ER-79-106 ER-80-83 ER-82-134 ER-83-80
Southwestern Bell Telephone Company	18,660 TR-79-213 TR-80-256
Union Electric Company	EO-86-36 EM-96-149 GR-97-393 GR-2000-512
Western Resources, Inc. d/b/a Gas Service	GR-93-240